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Government of the Province of Alberta

THE PETROLEUM AND NATURAL GAS CONSERVATION BOARD

REPORT TO

THE LIEUTENANT GOVERNOR IN COUNCIL

With Respect to the Applications under The Gas Resources Preservation Act of:

Canadian-Montana Pipe Line Company.

Trans-Canada Pipe Lines Limited, Trans-Canada Grid of Alberta Ltd., and Canadian Delhi Oil Ltd.

Western Pipe Lines.

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Government of the Province of Alberta

The Petroleum and Natural Gas Conservation Board

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The Lieutenant Governor in Council

With Respect to the Applications under The Gas Resources Preservation Act of:

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The Petroleum and Natural Gas Conservation Board, having publicly heard the applications under The Gas Resources Preservation Act of the aforelisted, having studied the evidence submitted at the public hearings, and having regard to the advice of its staff, to its own knowledge, and to its responsibilities under the Act, find as follows:

I.—IN THE MATTER OF THE ESTABLISHED RESERVES OF NATURAL GAS IN THE PROVINCE OF ALBERTA

The Board estimates the established reserves of natural gas in the Province of Alberta as of June 30, 1953 to be 11.5 trillion cubic feet.

The present estimate compares with the Interim Report estimate of 4.7 trillion cubic feet (December 31, 1950) and the March, 1952 Report estimate of 6.8 trillion cubic feet (December 31, 1951). The increase in estimated reserves is due to new discoveries, to further development of previous discoveries, and to new data and new interpretations related to them. Details of the new estimate appear in Appendix A and a graphical representation of the magnitude and location of the reserves is shown in Figure A-1.

II.—IN THE MATTER OF THE TRENDS IN EXPLORATION AND THE GROWTH OF THE RESERVES OF NATURAL GAS IN THE PROVINCE OF ALBERTA

The record of the growth of reserves to June 30, 1953, together with evidence and opinions of competent geologists and engineers convinces the Board that, with a continued incentive for exploration, the Province of Alberta can safely anticipate the development of further established reserves of natural gas at an average rate of at least 1¼ to 1½ trillion cubic feet per year for at least the next 8 to 10 years.

Statistics of the Province's record in discovering new gas reserves to June 30, 1953 show that in the aggregate established reserves of over 5 billion cubic feet have resulted from the drilling of each wildcat well. The corresponding figure to the end of 1951 is 6.3 billion cubic feet, while those to the end of 1950 and 1949 are 7.4 and 8.6 billion cubic feet per wildcat well. Having in mind the time lag required fully to evaluate the results of drilling, the Board believes the figure of 6 billion cubic feet per wildcat well to be realistic at the present time. Even assuming that the present figure of 6 billion cubic feet per well decreases to an average of 3 billion cubic feet per well, a continued incentive for exploration resulting in the drilling of 400 - 500 wildcat wells per year would bring about reserve additions of the order of 1¼ to 1½ trillion cubic feet per year. Appendix B presents the statistical details of Alberta's record of wildcat wells drilled and new reserves of gas discovered together with details of the Board's interpretation.

III.—IN THE MATTER OF THE PRESENT AND FUTURE REQUIREMENTS OF THE PROVINCE OF ALBERTA FOR NATURAL GAS

The Board estimates the actual requirements of the Proince of Alberta for natural gas for the 30 year period January 1, 1953 to December 31, 1982 to be 4.45 trillion cubic feet with a 1982 peak day requirement of 1160 million cubic feet. These figures will have to be revised from time to time.

The present estimate compares with the Interim Report estimate (January 1, 1951) of just under 3.1 trillion cubic feet and the March 1952 estimate (January 1, 1952) of 4.2 trillion cubic feet. Evidence of the applicants was in support of a figure near 4.2 trillion cubic feet, while that of the Canadian Western Natural Gas Company Limited and Northwestern Utilities, Limited suggested a little higher figure.

Details of the revised estimate are presented in Appendix C.

IV—IN THE MATTER OF MEETING THE 1953-1982 REQUIREMENTS OF THE PROVINCE OF ALBERTA FOR NATURAL GAS TOGETHER WITH THE PRESENT EXPORT COMMITMENTS OF THE PROVINCE

The Board estimates that established disposable reserves of the order of 6.4 trillion cubic feet are necessary to meet the annual and peak day requirements of the Province for the 30 year period 1953 - 1982 inclusive. A further reserve of 256 billion cubic feet is required to meet the present export commitments of the Province being 13.4 billion cubic feet to Dawson Creek, B.C., 210 billion cubic feet to the Pacific Northwest via Westcoast Transmission Company Limited, and 32.3 billion cubic feet (under The Gas Export Act) to the State of Montana via the Canadian-Montana Pipeline Company.

A detailed analysis of the availability of residue gas from oil field operations adjacent to the Northwestern Utilities, Limited system coupled with studies on the ability of presently connected and nearby dry gas fields demonstrate that the 30 year requirements of the area tributary to this system may readily be met. Reserves now connected to the Canadian Western Natural Gas Company Limited system are adequate for its supply only until about 1956. Further reserves of the order of 1,300 billion cubic feet (a figure contingent upon deliverability characteristics of the reserves) are necessary to ensure the 30 year requirements and the 1982 peak day. While analysis has demonstrated two adequate methods

of meeting this requirement from known reserves, the reserves of the Okotoks, Olds, Homeglen-Rimbey, Nevis fields and the Westerose area are recommended by the utility companies. The Board concures in this view. The requirements of the Medicine Hat area may easily be met from reserves in the Medicine Hat —Many Islands field. The requirements of the Peace River area of the Province of Alberta together with its export commitments may readily be met from reserves in the Peace River area. The requirements of the remainder of the Province may be met in part from small fields probably beyond reach of main line transportation systems and partly from other fields via main line systems. The present export commitments to the Canadian-Montana Pipeline Company may readily be met from the Pendant d'Oreille, Smith-Coulee and Black Butte fields. Detailed deliverability schedules showing the manner in which the presently established reserves might be used are presented, with discussions, in Appendix D. The schedules are believed practicable but are none the less primarily illustrative and could be greatly altered in internal detail without significantly changing the result.

V.—IN THE MATTER OF THE NATURAL GAS SURPLUS TO THE 1953-1982 REQUIREMENTS OF THE PROVINCE OF ALBERTA AND IN EXCESS OF THE PRESENT EXPORT COMMITMENTS OF THE PROVINCE

From the present established reserves of 11.5 trillion cubic feet some 4.8 trillion cubic feet are estimated to be surplus to the 1953 - 1982 requirements of the Province and to present export commitments.

Of this surplus gas some 217 billion cubic feet lies in the Peace River area of the Province, some 334 billion cubic feet is in the Pakowki Lake fields, some 232 billion cubic feet is in the Medicine Hat—Many Islands field, some 2,000 billion cubic feet is in the Pincher Creek field, and some 1,223 billion cubic feet is in the Cessford and nearby fields. The remaining surplus of some 800 billion cubic feet is scattered throughout central and northern Alberta. The bulk of this 800 billion cubic feet is presently considered beyond economic reach. The details concerning the surplus as shown in Appendix E are primarily illustrative and other reasonably interchangeable gas might be substituted for any part of the surplus.

VI.—IN THE MATTER OF THE EFFICIENT DEVELOPMENT AND UTILIZATION OF THE GAS RESOURCES OF THE PROVINCE WITH RESPECT BOTH TO THE PRESENT AND FUTURE REQUIREMENTS OF THE PROVINCE AND THE MARKETS OUTSIDE THE PROVINCE

The Board believes that efficient development gathering and utilization of the gas resources of the Province would be promoted by the institution of a "Trunk-Line" system operating within the Province as a common carrier under full Provincial jurisdiction and control.

Such a system would not, at the present time, extend either to the Peace River area or to the Pakowki Lake area, but it would facilitate interconnection of the bulk of the other reserves of the Province with the main market areas of the Province and with the "gate" on the Provincial border to markets east of Alberta. The system proposed by the Board is a modification of proposals submitted by Alberta Inter-Field Gas Lines Limited. Its essential facilities, as now anticipated, would include a line of some 24 inches in diameter extending from the Homeglen-Rimbey field south to Calgary, and then east by south-easterly to near Arrowwood from where a line of some 30 inches in diameter would extend eastward to the Alberta-Saskatchewan border. An early extension of this line from Homeglen-Rimbey to the Edmonton area is contemplated. The "Trunk-Line" system would accept for delivery either to Alberta markets or to markets east of Alberta gas delivered to it by other lines owned and operated by producers, the local utility companies, export companies or by the "Trunk-Line" system itself. Such a system, in the opinion of the Board, would promote conservation and efficient utilization of the gas resources, flexibility of development, joint and efficient use of all facilities and the sharing of markets. Moreover, as so strongly represented by Alberta Inter-Field Gas Lines Limited, it would strengthen the control of gas within the Province by Provincial authorities. Further details of the operation of the system and its advantages are discussed in Appendix F. Figure F-1 illustrates the general route of the "Trunk-Line" in relation to the location and magnitude of the reserves and the location of the markets.

VII.—IN THE MATTER OF THE MARKETS FOR ALBERTA GAS OUTSIDE OF THE PROVINCE

The Board is confident that the Canadian-Montana Pipeline Company can market all the gas covered by its application. The Board, however, is not satisfied that either Western Pipe Lines or Trans-Canada Pipe Lines Limited, et al, has substantiated its ability to market the amount of gas covered by its application.

Lack of evidence from distributors in the main consuming areas in Eastern Canada as to the amount of gas they are prepared to contract for constituted a weakness in the case presented by Trans-Canada Pipe Lines Limited, et al, particularly in view of the conflicting evidence given by witnesses presenting marketing evidence both as to the volumes of gas which could be sold and the retail prices which could be obtained for the gas. In the case of Western Pipe Lines, evidence given by Northern Natural Gas Company as to the amounts of gas they would take under a "contract" entered into in 1951, was inconclusive. Evidence on markets outside of Alberta is discussed in Appendix G.

VIII.—IN THE MATTER OF THE APPLICATION OF CANADIAN-MONTANA PIPELINE COMPANY

The applicant requests permission to remove from the Province of Alberta to the State of Montana all gas which may be produced from certain lands in the Pakowki Lake area. The applicant is "also ready and willing to purchase from other producers in the area any gas which by reason of its locality may be conveniently and logically dealt with by it".

The Board, finding some 334 billion cubic feet of gas in the Pakowki Lake area to be surplus to the requirements and present commitments of the Province, being fully satisfied that the applicant can sell the gas applied for at prices which would make the project economically feasible and being satisfied that the removal of this gas would not significantly prejudice the schemes of the other applicants, is prepared, with the approval of the Lieutenant Governor in Council, to issue an export permit to Canadian-Montana Pipeline Company subject to certain terms and conditions.

IX.—IN THE MATTER OF THE APPLICATION OF TRANS-CANADA PIPE LINES LIMITED TRANS-CANADA GRID OF ALBERTA LTD., AND CANADIAN DELHI OIL LTD.

The applicants request permission to remove from the Province of Alberta to Canadian markets east of the Province a maximum of 365 million cubic feet of gas per day for a period of 25 years. They propose selling this gas in the Province of Saskatchewan, Manitoba, Ontario and Quebec.

The Board finds that there is gas surplus to the present and future requirements and the present export commitments of the Province, over and above that applied for by Canadian-Montana Pipeline Company but exclusive of that applied for by Western Pipe Lines, which for practical purposes is sufficient through the "Trunk-Line" system to meet the applicants' requirements for a 25 year period. The Board, however, is not fully satisfied that the applicants can sell sufficient gas in Ontario and Quebec at prices which would make the project economically feasible. Moreover, on the basis of evidence received, the Board cannot be certain that the storage fields of Southern Ontario, necessary to the applicant's project, are adequate or even that they will be available for the applicants' use.

Accordingly the Board is, at this time, unable to state whether or not the granting of an export permit to the applicants would be in the best interests of the Province of Alberta. The Board, therefore, reserves its decision on the application and announces its intention to reconvene the hearings to allow the applicants to:

(a) present concrete evidence in the form of contracts in support of their ability to market the amount of gas applied for at prices which would make the project economically feasible;

(b) present evidence as to the availability of and the deliverability characteristics of the proposed storage fields;

(c) clarify their application with respect to the maximum of 365 million cubic feet of gas per day in the light of the greater quantities assumed in their evidence; and

(d) state their position with respect to the acceptance of gas through the proposed "Trunk-Line" system.

X.—IN THE MATTER OF THE APPLICATION OF WESTERN PIPE LINES

The applicant requests permission to remove from the Province of Alberta a maximum of 275 million cubic feet of gas per day for a period of 30 years. (Phase I). During this phase the applicant proposes selling gas in the Provinces of Saskatchewan and Manitoba, and to Northern Natural Gas Company in the United States. The applicant further proposes "to apply hereafter when adequate reserves and deliverabilities therefore have become established, for permission to export an additional 275 million cubic feet per day to make provision for deliveries of natural gas to supply markets in Eastern Canada." (Phase II).

The Board finds that there is surplus gas, over and above that applied for by Canadian - Montana Pipeline Company, but exclusive of that applied for by Trans-Canada Pipe Lines Limited, et al, which is sufficient through the "Trunk-Line" system to meet the applicant's requirements for a 30 year period. The Board, however, is not fully satisfied that the applicant can sell sufficient gas to Northern Natural Gas Company at a price which would make the project economically feasible. Furthermore, the applicant has not, in the opinion of the Board, fully demonstrated the feasibility of Phase II. While the quantities of gas required for Phase II are not included in the present application, the Board considers this phase an integral part of the overall plan of Western Pipe Lines.

Accordingly the Board is, at this time, unable to state whether or not the granting of an export permit to the applicant would be in the best interests of the Province of Alberta. The Board, therefore, reserves its decision on the application and announces its intention to reconvene the hearings to allow the applicants to:

(a) present more clear-cut evidence as to the amount of gas Northern Natural Gas Company will be obliged to take during Phase I under the existing "contract" and the price it will pay for it;

(b) present the amendment to the existing "contract" referred to in page 1 of Exhibit 44;

(c) present evidence as to what assurance the Board and the Province would have that Western Pipe Lines could and would perform its commitment to proceed with Phase II if sufficient gas were available; and

(d) state its position with respect to the acceptance of gas through the proposed "Trunk-Line" system.

The Board intends to reconvene the hearings of the applications of Trans-Canada Pipe Lines Limited, et al, and Western Pipe Lines at a date early enough to allow the Board to render its decision well before the start of the 1954 construction season.

Respectfully submitted,

I. N. McKinnon, Chairman.
D. P. Goodall, P. Eng., Deputy Chairman.
G. W. Govier, P. Eng., Board Member.

Dated at the City of Calgary, in the Province of Alberta, this 24th day of November, A.D., 1953.

APPENDIX A

IN THE MATTER OF ESTABLISHED RESERVES OF NATURAL GAS IN THE PROVINCE OF ALBERTA

The Board's findings with respect to the estimated gas reserves of the Province as of December 31, 1951, were published in its report of March 29, 1952. At that time the established reserves of natural gas were estimated at 6.8 trillion cubic feet. During the year and a half following that estimate there has been a tremendous increase in gas discoveries and expansion of previous discoveries throughout the Province.

From evidence submitted during its 1953 hearings and from information obtained from other sources, the Board now finds the established reserves of natural gas in the Province to be 11.5 trillion cubic feet as of June 30, 1953 (not corrected for 1953 production). This is an increase of 4.7 trillion cubic feet over the Board's previous estimate. About 35 per cent of this increase is due to expansion of previously known reserves and 65 per cent to new discoveries. Of the previously known reserves about 73 per cent of that increase is the result of further development at Cessford, Medicine Hat and Pincher Creek.

New discoveries and previous discoveries on which there was insufficient information to make an estimate at the time of publication of the 1952 report, but which have seen further development since that time, now account for nearly 3.0 trillion cubic feet of established reserves. Over half of this amount consists of the reserves of Homeglen-Rimbey, Bonnie Glen and Nevis. The rest is made up from some eighty named fields or areas of which about one half have estimated established reserves of less than ten billion cubic feet of gas each.

As in previous hearings there was a considerable variation of opinion as to the reserves of certain fields. Total reserve estimates for the Province were, however, in fairly close agreement. The consulting firm of DeGolyer and McNaughton, acting for Trans-Canada Pipe Lines Limited, Trans-Canada Grid of Alberta Ltd., and Canadian Delhi Oil Ltd., presented a complete new study of the Provincial reserves. Their estimate of reserves available for sale as of January 1, 1953, was 13.45 trillion cubic feet. This is an increase of more than 5.0 trillion cubic feet over their January 1, 1951 estimate. An estimate of 10.94 trillion cubic feet of established reserves as of June 30, 1953, was submitted by Dr. W. C. Gussow, consulting geologist and Mr. R. Pot of the consulting firm of Trafford and Associates on behalf of Mid-Continent Pipe Lines Limited. Mr. David G. Hawthorn of Petroleum Consultants on behalf of Western Pipe Lines, estimated the established reserves of the Province as of January 1, 1953 at 10.8 trillion cubic feet. Mr. John F. Dodge for Canadian-Montana Pipeline Company, submitted estimates for the most prominent reserves of the Province but his study did not include a Provincial total.

Estimates were also submitted for certain fields by Mr. R. E. Davis for Northwestern Utilities, Limited and Canadian Western Natural Gas Company Limited,

Mr. Maurice F. Teskey for Britalta Petroleums Limited, Mr. Henry J. O'Shea for New British Dominion Oil Company Limited, Mr. Floyd Aaring for Canadian Gulf Oil Company and Mr. J. W. Ten Broeke for Shell Oil Company. In addition to the above submissions, the Board's geological and engineering staffs made a complete study of the gas reserves of the Province. The results of their study were not presented at the hearing, but were taken into consideration by the Board in its review of other estimates.

In its Interim Report of 1951 and again in its 1952 report, the Board expressed the following opinion as to what should be considered as "established reserves of disposable gas".

> "It considers that if the present and future needs of the Province are to be adequately protected, there should be a reasonable expectancy that such gas reserves are available from presently known discoveries and that the gas can be developed economically and made available for use when and as required."

The Board has had the same concepts in mind in reaching its conclusions from the study of the data presented by the various estimators. These conclusions are summarized in Table A-1 and presented graphically in Figure A-1. Table A-1 lists individually all reserves estimated by the Board at 10 billion or more cubic feet and, in addition, some smaller reserves which are available for local use or are situated adjacent to larger reserves. The table also shows a total for some eighty small reserves of less than 10 billion cubic feet not listed individually.

Referring then to Table A-1:—

Column	Presents
1.	Name of field or best known well or wells.
2.	Geological formation or zone from which gas is obtained.
3.	Estimated volume of gas in the reservoir June 30, 1953, expressed in billions of cubic feet at standard conditions (14.4 p.s.i.a. and 60°F).
4.	Discount applicable to "Gas in Place" (column 3) to account for the gas left in the reservoir at abandonment.
5.	Discount applicable, after that for the reservoir loss, to account for surface loss. This factor includes (where applicable) allowance for gas flared, operational loss, field and/or plant fuel, and processing shrinkage attending the removal of carbon dioxide, hydrogen sulphide, propane and butanes plus.
6.	Established reserves; reserves of disposable gas which in the opinion of the Board may be reasonably counted upon. The reserves are expressed in billions of cubic feet at standard conditions and are based upon the figures of columns 3, 4 and 5.
7.	Comments of specific application to individual fields.

COMMENTS WITH REGARD TO CERTAIN FIELDS

New Discoveries

Table A-1 lists six fields with estimated reserves of 100 billion or more cubic feet which were discovered since publication of the 1952 report or which had not produced sufficient information for an estimate at that time.

Bonnie Glen

This field was discovered at the close of 1951 and was mentioned as a potential gas reserve of importance in the Board's 1952 report. The development of the field for crude oil production has been rapid and a fairly reliable estimate can now be made of the gas reserves.

The field is situated about nine miles south of the Leduc-Woodbend field and forms part of the northeast-southwest trending string of Devonian reef deposits extending from Morinville south through Leduc and for some forty-five miles or more farther southwest. This chain of reef deposits is frequently referred to as the "Golden Trend" owing to the prolific oil and gas fields discovered in it.

The Bonnie Glen reservoir has a gas cap averaging about 204 feet thick and an average thickness of about 252 feet of oil saturation above the water table. Gas in the gas cap will be conserved in the interest of oil recovery but solution gas produced with oil will be available for market. The Board estimates the gas cap reserve at 406 billion cubic feet and solution gas reserves at 338 making a total of 744 billion cubic feet of disposable gas for this field.

Westerose

This field also lies on the "Golden Trend" about twenty-two miles southwest of the Leduc-Woodbend field and three miles southwest of Bonnie Glen. It was discovered in 1952 and production is from the same horizon in the Devonian as other fields on the reef chain. Owing to the small amount of development that had taken place in this field by the close of the hearings, the size of the reservoir is unknown. The gas cap appears to have an average thickness of 190 feet and the oil section is about 215 feet thick. The Board estimates 80 billion cubic feet of disposable gas for the gas cap (production of which will be deferred in the interest of oil production) and 50 billion cubic feet for the solution gas. This solution gas will likely be required for pressure maintenance purposes.

Homeglen-Rimbey

This is the latest and farthest south discovery along the "Golden Trend". This field had received very little development at the close of the hearings and the estimators varied considerably in their predictions. All were, however, quite optimistic and expressed the opinion that the reserves of the field might be much greater than the estimate submitted. After giving consideration to some information made avail-

able after the hearings closed, the Board has adopted an interim estimate of 500 billion cubic feet of disposable gas for the field with the expectation that further development will prove this figure to be low. Since the oil saturated section in this reservoir is relatively thin it is to be expected that some of the gas cap will be available for market much earlier than will the reserves of gas cap gas in other fields mentioned along the trend.

Nevis

This field was discovered in March 1952. By mid 1953 seven productive wells had been drilled in the field and gave conclusive evidence that a substantial gas reserve was present. Gas occurs in the Devonian in the same horizon as oil production is obtained at Stettler about eight miles east of the Nevis field. There appears to be only a minor amount of crude oil associated with the gas in this reservoir and it is expected that the gas will immediately be available for market. The Board estimates the Devonian reserves of the field at 370 billion cubic feet and Lower Cretaceous reserves at 20 billion cubic feet of disposable gas.

Okotoks

This field was discovered by Shell Oil Company in 1951 and was mentioned as an interesting discovery in the Board's 1952 report. Wells which have been drilled now outline a fairly extensive reserve although the boundaries of the field are still in doubt. Production is obtained from Devonian limestone. The gas carries a high percentage of hydrogen sulphide and other non combustible gases as well as some liquid hydrocarbons. The marketing of the gas will be contingent upon the construction of processing facilities, the economics of which will at least be partially dependent on the sale of sulphur.

Estimates of the disposable reserves of this field varied considerably owing chiefly to the lack of control as to area. The Board, after considering all evidence, now adopts an estimate of 100 billion cubic feet of disposable gas for the field.

Fort Saskatchewan

This Viking sand discovery was made in 1949 but was not exploited until 1951 when development drilling started in the field. At mid year 1953 fourteen wells had been completed in the field, and preparations had been made to use the gas for local industry and in the Northwestern Utilities system. This gas does not require processing, it is close to a market, and is available for immediate use. The Board estimates the reserve of disposable gas to be 100 billion cubic feet.

Expanded Reserves of Previous Discoveries

Cessford

In its 1952 report the Board assigned 440 billion cubic feet as the total disposable gas reserve of the Viking, Basal Colorado and Sunburst zones in this field. During 1952 and the first half of 1953 quite a few new wells were drilled throughout the

area. A fairly large percentage of these were successful gas completions proving up greater reserves. On the other hand, a number of dry holes were drilled in fairly close proximity to previous producers demonstrating the erratic distribution of the gas bearing sands. As expressed in its 1952 report, the Board still considers that caution should be exercised in estimating the areal extent of these reserves. Gas appears to be distributed in irregular patches over a wide area. Although the Board feels that a relatively large number of dry holes will be drilled in developing these reserves, it estimates that 965 billion cubic feet of disposable gas will be developed throughout the entire area.

Medicine Hat

The area covered by the Board's 1952 estimate of 513 billion cubic feet of disposable gas in the Medicine Hat sand has been extended both to the north and to the east since that time by the drilling of new wells. The Board now estimates the established reserves of this field at 830 billion cubic feet.

Pincher Creek

Since publication of the 1952 report, Canadian Gulf Oil Company has completed three new wells on this structure. The company has also carried out further seismic work and its interpretation of the data thus obtained was presented to the Board during the 1953 hearings. Engineers of the applicant companies and the Board's staff had the opportunity to study the revised seismic map prepared by Canadian Gulf Oil Company and to use the new information obtained through the drilling of wells. Estimates presented to the Board of disposable gas in the reservoir varied from 1720 to 2290 billion cubic feet. After considering all evidence submitted, the Board has estimated a reserve of 2000 billion cubic feet of disposable gas for the field. This is about 19 per cent greater than the 1680 billion cubic feet estimate of the Board's 1952 report.

Small Reserves and New Discoveries

In Table A-1 a total of 325.5 billion cubic feet of disposable gas is credited to small fields each with estimated reserves of less than 10 billion cubic feet. For the most part, these are isolated reserves which would not be economical to market unless located along the route of a pipeline serving other reserves or unless the gas can be used locally. Approximately eighty pools are included in this category. A large proportion of the small reserves are in the Lower Cretaceous sand accumulations. These are difficult to evaluate even after the reserve has apparently been drilled out. The sand bodies are, as a rule, very irregular as to shape, thickness and permeability, and an economical spacing pattern for wells does not provide sufficient information for a reliable estimate of reserves. Some, no doubt, will develop into major reserves with further drilling, but many appear to have little prospects for more than minor increases.

During the year and a half since publication of the Board's 1952 report on reserves, there have been approximately 173 new gas discoveries in the Province—128 of these

were made in 1952 and 45 in the first half of 1953. Only a few of these have reserves over 10 billion cubic feet as estimated from the information available as of mid 1953. Many of them had not, at that time, been developed beyond the initial discovery and estimates of such reserves were not attempted by the Board.

Table A-2 of the Board's 1952 report presented totals of all gas strikes within the Province during 1951 by geological ages of the gas bearing reservoir and by geographic location represented by census divisions. Table A-2 of the present report shows the total number of gas strikes made in 1952 and during the first six months of 1953 by geological ages of the reservoirs and by location within the Province. The geographic classification has been made by "map area", 1 S, 1 N, etc., each group being one half of the standard well location map published by the Board. It has been adopted for this study as a more convenient subdivision of the Province than the Census Division. For comparative purposes, the data shown in Table A-2 of the 1952 report has been reclassified geographically and included in Table A-2 of the present report. The locations of the 1952 and 1953 strikes are shown on the map of the Province published as Figure A-2.

It will be observed that central Alberta still leads in new gas discoveries, the larger proportion of which is made in reservoir of Cretaceous age. An analysis of reserves discovered during this period, based on our present knowledge, indicates, however, that the Paleozoic reservoirs are capable of contributing a greater volume of gas than those of the Cretaceous. As previously stated, over half of the reserves attributed to new discoveries since the publication of the 1952 report are contained in the Paleozoic reservoirs of Homeglen-Rimbey, Bonnie Glen and Nevis.

Table A-1

The Petroleum and Natural Gas Conservation Board

ESTABLISHED RESERVES OF NATURAL GAS IN THE PROVINCE OF ALBERTA, JUNE 30, 1953 (3)

1	2	3	4	5	6	7
FIELD	ZONE	Estimated Original Gas in Place billions of cubic feet	Discount for Reservoir Loss per cent	Discount for Surface Loss, Etc. per cent	Disposable Gas (3) billions of cubic feet	REMARKS
Acheson	Viking	13.1	20	5	10.0	Production may be deferred until oil produced from limestone reservoir.
	Blairmore	73.3	25	10	49.5	Production may be deferred until oil produced from limestone reservoir. Reserve adjusted by 1.1 factor to convert to 1000 B.T.U. basis.
	Leduc (D-3) Solution	60.6	45(i)	25	24.0	(i) Reservoir loss high due to possibility of pressure maintenance by water injection. Reserves adjusted by 1.2 factor to convert to 1000 B.T.U. basis.
Ashmont	Lower Cretaceous	12.4	20	5	10.0	Possible local utility.
Athabasca	Lower Cretaceous	9.3	20	5	7.0	Supplies local utility.
	Wabamun (D-1)	6.2	15	5	5.0	Supplies local utility.
Bantry Tilley	Sunburst	12.4	15	5	10.0	Possible local supply.
Beaverhill Lake	Viking	39.5	20	5	30.0	
Belloy	Gething	47.0	10	5	40.0	
	Mississippian	24.0	10	10(i)	20.0	(i) Contains condensate. May require processing.
Big Valley	Viking	6.2	15	5	5.0	
	Nisku (D-2) Solution	8.9	30	20	5.0	Plant to be constructed for processing.
Big Valley North and Fenn	Viking	6.2	15	5	5.0	
	Nisku (D-2) Solution	53.6	30	20	30.0	
Black Butte-Pinhorn	Bow Island	10.5	20	5	8.0	Gas supply for Canadian Montana Gas Co. Ltd.
	Ribbon	14.9	15	5	12.0	
	Ellis	19.8	20	5	15.0	
	Rundle	12.4	10	10(i)	10.0	(i) Requires processing to remove H^2S.
Bolloque Lake	Viking	4.2	25	5	3.0	Presently considered beyond economic reach.
	Blairmore	11.8	20	5	9.0	Presently considered beyond economic reach.
Bon Accord-Lost Point Lake	Viking	55.7	15	5	45.0	To be connected to N.U.L. System.
Bonnie Glen	Leduc Gas Cap	531.0	10	15	406.0	Deferred until most of oil is produced. Adjusted by 1.23 factor to convert to 1000 B.T.U. basis.
	Leduc Solution	746.0	35	30	338.0	Adjusted by 1.23 factor to convert to 1000 B.T.U. basis.
Bonnyville	Lower Cretaceous	5.2	20	5	4.0	Supplies local utility.

Table A-1 (Continued)

1	2	3	4	5	6	7
FIELD	ZONE	Estimated Original Gas in Place billions of cubic feet	Discount for Reservoir Loss per cent	Discount for Surface Loss, Etc. per cent	Disposable Gas (3) billions of cubic feet	REMARKS
Boyle Mustang-Amisk Lake	Upper Grand Rapids	18.4	20	5	14.0	Reservoir loss of 20% used because of low reservoir pressures.
	Middle Grand Rapids	1.3	20	5	1.0	Presently considered beyond economic reach.
	Lower Grand Rapids	6.6	20	5	5.0	
	McMurray	6.6	20	5	5.0	
	Nisku (D-2)	33.0	20	5	25.0	
Bow Island	Bow Island	21.0	20	5	16.0	Used as a storage field by C.W.N.G. Co. Ltd.
Brooks N.E.	Bow Island	6.2	15	5	5.0	Supplies local utility.
	Sunburst	5.9	10	5	5.0	Supplies local utility.
Brooks-Tilley	Milk River	25.0	20	5	19.0	Supplies local utility.
Campbell-Namao	Basal Blairmore	58.8	15	20(i)	40.0	(i) Requires processing with some gathering difficulties.
Castor	Viking	22.3	15	5	18.0	Possible supply for local utility.
	Upper Blairmore	2.3	10	5	2.0	Possible supply for local utility.
Cessford-Sunnynook-Bullpound-Steveville	Viking	73.4	20	5	55.0	Appears to consist of several reservoirs.
	Basal Colorado	856.0	20	5	650.0	Appears to consist of several reservoirs.
	Sunburst	343.0	20	5	260.0	Appears to consist of several reservoirs.
Clive	Viking	7.9	20	5	6.0	
	Basal Blairmore	8.7	15	5	7.0	
	Devonian Solution	3.6	30	20	2.0	
Comrey	Bow Island	12.9	10	5	11.0	
Consort	Viking	52.7	20	5	40.0	Presently considered beyond economic reach.
Countess	Bow Island	70.0	10	5	60.0	
Dixonville	Gething	31.6	10	5	27.0	Presently considered beyond economic reach.
Donalda	Viking	9.9	15	5	8.0	Possible supply for local utility.
	Detrital	2.5	15	5	2.0	Possible supply for local utility.
Drumheller	Basal Blairmore	2.5	15	5	2.0	Possible supply for local utility.
	Nisku (D-2) Solution	7.7	35	20	4.0	Possible supply for local utility.
Duchess	Bow Island	6.6	20	5	5.0	
	Basal Colorado	10.5	20	5	8.0	
Duhamel	Viking	5.3	20	5	4.0	Possible source for local supply.
	Basal Blairmore	8.7	15	5	7.0	Possible source for local supply.
	Nisku Solution	7.1	30	20	4.0	Possible source for local supply.
	Leduc Solution	5.4	30	20	3.0	Possible source for local supply.

Eaglesham	Peace River	2.6	20	5	2.0	
	Mississippian	12.9	10	5	11.0	
Elk Point	Colony	1.4	25	5	1.0	Supplies local utility.
Erskine	Basal Blairmore	5.9	20	15(i)	4.0	(i) Wet, may require processing.
	Leduc Gas Cap	4.9	10	10(i)	4.0	(i) Wet, may require processing.
	Leduc Solution	3.6	30	20	2.0	
Etzikom	Bow Island	74.3	15	5	60.0	
Excelsior	Viking	9.2	20	5	7.0	May be deferred until oil produced from Devonian reservoir.
	Basal Blairmore	31.6	10	5	27.0	May be deferred until oil produced from Devonian reservoir.
Foremost	Bow Island	34.8(i) 29.1(ii)	20(i) 24(ii)	5	21.0	(i) Original. (ii) Less 5.7 produced to January 1, 1953.
Fort Saskatchewan	Viking	124.0	15	5	100.0	
Golden Spike	Viking	7.4	15	5	6.0	Used in repressuring Leduc reservoir.
	Basal Blairmore	29.2	10	5	25.0	Used in repressuring Leduc reservoir.
	Wabamun	37.0	10	10(i)	30.0	(i) Wet, may require processing. Used in repressuring Leduc reservoir.
	Nisku Gas Cap	3.7	10	10	3.0	Used in repressuring Leduc reservoir.
	Nisku Solution	11.7	25	20	7.0	Used in repressuring Leduc reservoir.
	Leduc Solution	106.8	25	25	60.0	All gas is deferred until oil is produced from Leduc reservoir.
Gordondale	Peace River	44.6	15	5	36.0	
Hamelin Creek	Peace River	6.6	20	5	5.0	
	Gething	81.9	10	5	70.0	
Hamilton Lake	Viking	56.1	25	5	40.0	Presently considered beyond economic reach.
Hanna	Viking	4.1	20	5	3.1	To supply local utility.
	Blairmore	4.7	15	5	3.8	To supply local utility.
	Banff	1.8	20	5	1.4	To supply local utility.
Homeglen-Rimbey	Leduc Gas Cap	735.0	15	20(i)	500.0	(i) Wet, requires processing.
Jarvie	Viking	2.8	25	5	2.0	Presently considered beyond economic reach.
	Basal Blairmore	9.9	15	5	8.0	Presently considered beyond economic reach.
Joseph Lake-	Viking Gas Cap	63.8	20	15	43.4	Reserves adjusted by 1.085 factor to convert to 1000 B.T.U. basis.
Armena Camrose	Viking Solution	44.1(i) 42.3(ii)	30.0(i) 31.6(ii)	25	21.7	(i) Original. (ii) Less 1.8 produced to Jan. 1, 1953. Reserves are adjusted by 1.085 factor to convert to 1000 B.T.U. basis.
Jumping Pound	Rundle	517(i) 503.6(ii)	10(i) 10.3(ii)	17	375.0	(i) Original. (ii) Less 13.4 produced to Jan. 1, 1953.

Table A-I (Continued)

1	2	3	4	5	6	7
FIELD	ZONE	Estimated Original Gas in Place billions of cubic feet	Discount for Reservoir Loss per cent	Discount for Surface Loss, Etc. per cent	Disposable Gas (3) billions of cubic feet	REMARKS
Kessler	Viking	18.3	25	5	13.0	Presently considered beyond economic reach.
Lac La Biche	Viking	45.1	30(i)	5	30.0	(i) High because of low reservoir pressure. Presently considered beyond economic reach.
	McMurray	14.0	25(i)	5	10.0	(i) High because of low reservoir pressure. Presently considered beyond economic reach.
Leduc Woodbend	Viking	16.5	20	5	12.0	0.6 produced to Jan. 1, 1953.
	Lower Cretaceous	187.0(i) 186.3(ii)	10(i) 10(ii)	10	150.9	(i) Original. (ii) Less 0.6 produced to Jan. 1, 1953. Reserves are adjusted by 1.16 factor to convert to 1000 B.T.U. basis.
	Nisku Gas Cap	60.6	10	15	46.4	Reserves are adjusted by 1.16 factor to convert to 1000 B.T.U. basis.
	Nisku Solution	239.3(i) 225.5(ii)	25(i) 26.5(ii)	30	116.0	(i) Original. (ii) Less 11.9 produced to Jan. 1, 1953. Reserves are adjusted by 1.16 factor to convert to 1000 B.T.U. basis.
	Leduc Gas Cap	564.0(i) 535.0(ii)	10(i) 10.7(ii)	15	406.0	(i) Original. (ii) Less 25.0 produced from Atlantic No. 3. Reserves are adjusted by 1.16 factor to convert to 1000 B.T.U. basis.
	Leduc Solution	302.5(i) 278.1(ii)	40(i) 43.5(ii)	30	110.0	(i) Original. (ii) Less 21.0 produced to Jan. 1, 1953. Reserves are adjusted by 1.16 factor to convert to 1000 B.T.U. basis.
Legal Fairydell	Basal Blairmore	70.1	10	5	60.0	
Lindbergh	Viking	4.2	25	5	3.0	Supplies local utility.
	Colony	7.0	25	5	5.0	Supplies local utility.
Lloydminster	Colony	9.8	40	15	5.0	Supplies local utility.
	Sparky	8.3	60	40	2.0	Supplies local utility.
Majeau Lake	Viking	4.0	20	5	3.0	Presently considered beyond economic reach.
	Lower Cretaceous	18.6	15	5	15.0	Presently considered beyond economic reach.
	Rundle	26.2	10	15(i)	20.0	(i) Wet, requires processing. Presently considered beyond economic reach.

Malmo	Viking	3.7	15	5	3.0	Possible source for local supply.
	Basal Blairmore	7.4	15	5	6.0	Possible source for local supply.
	Basal Blairmore Solution	3.6	30	20	2.0	Possible source for local supply.
	Nisku Gas Cap	3.7	10	10	3.0	Possible source for local supply.
	Nisku Solution	5.4	30	20	3.0	Possible source for local supply.
	Leduc Gas Cap	1.2	10	10	1.0	Possible source for local supply.
	Leduc Solution	3.6	30	20	2.0	Possible source for local supply.
Manyberries	Upper Bow Island	7.9	20	5	6.0	
	Lower Bow Island	73.0	15	5	59.0	
Medicine Hat	Medicine Hat ss.	1357(i) 1194(ii)	20(i) 22.7(ii)	10	830.0	(i) Original. (ii) Less 163.0 produced to Jan. 1, 1953.
	Bow Island	13.2	20	5	10.0	
	Ellis	19.8	20	5	15.0	
Minnehik-Buck Lake	Rundle	24.7	10	10(i)	20.0	(i) Wet, may require processing. Presently considered beyond economic reach.
Morinville	Viking	2.8	25	5	2.0	
	Basal Blairmore	148.6	15	5	120.0	
Nevis	Lower Cretaceous	24.8	15	5	20.0	
	Devonian	513.0	10	20(i)	370.0	(i) Wet, requires processing.
New Norway	Viking	2.6	20	5	2.0	Possible local supply.
	Blairmore	5.9	10	5	5.0	Possible local supply.
	Nisku	5.7	30	25	3.0	Possible local supply.
Normandville	Gething	12.4	15	5	10.0	Presently considered beyond economic reach.
Oberlin	Viking	0.6	20	5	0.5	Supplies local utility.
	Basal Blairmore	4.0	20	5	3.0	Supplies local utility.
Olds	Wabamun	55.6	10	20(i)	40.0	(i) Wet, requires processing.
Okotoks	Wabamun	278.0	10	60(i)	100.0	(i) Has very high H_2S and CO_2 content.
Oyen	Viking	23.7	20	5	18.0	Presently considered beyond economic reach.
Patricia	Sunburst	11.7	10	5	10.0	
Pendant D'Oreille (includes Cal. Std. Foremost area)	Bow Island	238.60(i) 231.8(ii)	20(i) 20.5(ii)	5	175.0	(i) Original. (ii) Less 6.8 produced to Jan. 1, 1953. Presently supplies Canadian Montana Gas Company Ltd.
Phil Can	Gething	10.5	10	5	9.0	Presently considered beyond economic reach.
	Mississippian	4.9	15	5	4.0	Presently considered beyond economic reach.
Picardville-Fairydell	Viking	85.5	20	5	65.0	
Pigeon Lake	Leduc	13.1	10	15(i)	10.0	(i) Wet, may require processing.
Pincher Creek	Rundle	3000.0	10	26(i)	2000.0	(i) Plant processing losses.
Pouce Coupe	Peace River	75.4(i) 74.5(ii)	15(i) 19.4(ii)	5	60.0	(i) Original. (ii) Less 0.9 produced to Jan. 1, 1953.
	Gething	17.6	10	5	15.0	

1	2	3	4	5	6	7
FIELD	ZONE	Estimated Original Gas in Place billions of cubic feet	Discount for Reservoir Loss per cent	Discount for Surface Loss, Etc. per cent	Disposable Gas (3) billions of cubic feet	REMARKS
Princess-Steveville-Denhart	Basal Colorado	118.4	20	5	90.0	
	Sunburst	64.4	15	5	52.0	
	Rundle	6.6	20	5	5.0	
	Jefferson	45.8(i) 39.8(ii)	15(i) 17.2(ii)	15	28.0	(i) Original. (ii) Less 6.0 produced to Jan. 1, 1953.
Provost	Viking	118.4	20	5	90.0	Presently considered beyond economic reach.
	Lower Cretaceous	5.3	20	5	4.0	Presently considered beyond economic reach.
Redwater	Viking	14.0	25	5	10.0	Supplies local utility.
	Leduc Solution	306.5(i) 295.2(ii)	60(i) 61.5(ii)	45	62.5	(i) Original. (ii) Less 9.0 produced to Jan. 1, 1953. Reserves are adjusted by 1.25 factor to convert to 1000 B.T.U. basis.
Rochester	Viking	5.3	20	5	4.0	Presently considered beyond economic reach.
	Upper Blairmore	3.9	20	5	3.0	Presently considered beyond economic reach.
	Clearwater	11.9	20	5	9.0	Presently considered beyond economic reach.
	Glauconite	3.9	20	5	3.0	Presently considered beyond economic reach.
	Basal Blairmore	5.0	15	5	4.0	Presently considered beyond economic reach.
	Wabamun	6.2	15	5	5.0	Presently considered beyond economic reach.
Rolling Hills	Bow Island	12.4	15	5	10.0	Possible local supply.
Rosalind North	Basal Blairmore	11.7	10	5	10.0	Possible local supply.
Rycroft	Gething Non Associated	8.3	15	5	6.7	To supply local utility.
	Associated	5.7	10	5	4.9	To supply local utility.
Sibbald	Viking	39.5	20	5	30.0	Presently considered beyond economic reach.
Smith Coulee	Bow Island	13.2	20	5	10.0	Supplies Canadian Montana Gas Co. Ltd.
St. Albert	Viking	2.6	20	5	2.0	
	Lower Cretaceous	70.2	10	5	60.0	
Stettler	Nisku Solution	34.6	35	20	18.0	
St. Paul	Blairmore	3.9	20	5	3.0	Supplies local utility.
Suffield	Milk River	25.0	20	5	19.0	Supplies local utility.
Sylvan Lake	Blairmore	11.7	10	5	10.0	
	Mississippian	18.5	10	10(i)	15.0	(i) Wet, may require processing.
Tangent	Peace River	10.5	50(i)	5	5.0	(i) Reservoir pressure very low.
	Gething	118.5	20	5	90.0	
	Triassic	92.2	20	5	70.0	
Three Creeks	Gething	11.7	10	5	10.0	Presently considered beyond economic reach.

Turner Valley	Rundle Gas Cap	—	—	35	230.0	
	Rundle Solution	—	—	35	140.0	
Valleyview	Peace River	5.3	20	5	4.0	Presently considered beyond economic reach.
	Gething	11.8	20	5	9.0	Presently considered beyond economic reach.
Viking-Kinsella	Viking	1139.5(i) 947.0(ii)	25(i) 30.1(ii)	5	629.0	(i) Original. (ii) Less 192.5 produced to Jan. 1, 1953.
	Blairmore	2.6	20	5	2.0	
	Nisku	1.3	20	5	1.0	
Villeneuve	Viking	11.8	20	5	9.0	
Westcott	Rundle	19.6	10	15	15.0	Presently considered beyond economic reach.
West Drumheller	Basal Blairmore	3.7	15	5	3.0	To supply local utility. Plant being installed.
	Jefferson Gas Cap	3.9	10	15	3.0	To supply local utility.
	Jefferson Solution	25.0	35	20	13.0	To supply local utility.
Westerose	Leduc Gas Cap	98.8	10	10	80.0	Deferred until oil is produced.
	Leduc Solution	111.1	40	25	50.0	Deferred by reinjection.
Westerose South	Leduc	41.7	10	20(i)	30.0	(i) Wet, may require processing.
Whitelaw	Gething	111.5	15	5	90.0	Supplies local utility.
	Triassic	58.5	10	5	50.0	
Wildmere	Lower Cretaceous	7.9	20	5	6.0	Supplies local utility.
Wildunn Creek	Viking	17.5	10	5	15.0	
Wizard Lake	Viking	2.5	15	5	2.0	
	Lower Cretaceous	9.9	15	5	8.0	
	Leduc Solution	189.3	35	30	86.1	Reserves are adjusted by 1.23 factor to convert to 1000 B.T.U. basis.
Total of other reserves less than 10 billion cubic feet not listed above.					325.5	
				Total	11,452.5	

GENERAL NOTES:

(1) Unless otherwise noted reservoir loss is calculated as 10% of original gas in place except in particular cases where the following losses pertain:

Sand thickness 10-15 feet	Reservoir loss—15%
Sand thickness 5-10 feet	Reservoir loss—20%
Sand thickness 0-5 feet	Reservoir loss—25%

(2) Surface loss is taken as 5% for all dry gas, and varies for wet gas depending upon its composition.

(3) Disposable reserves as at June 30, 1953, with production deducted to December 31, 1952, only.

Table A-2

GAS STRIKES, JANUARY 1, 1951 to JUNE 30, 1953

Map Area	Upper Cretaceous*			Lower Cretaceous			Jurassic			Triassic			Paleozoic			Total Wells			Total Strikes		
			6 mos.			6 mos.			6 mos.			6 mos.			6 mos.			6 mos.			6 mos.
	1951	1952	1953	1951	1952	1953	1951	1952	1953	1951	1952	1953	1951	1952	1953	1951	1952	1953	1951	1952	1953
1 S	1	2	5												2	1	2	6	1	2	7
1 N	12	8	1	6	2	1								1		16	10	2	18	11	2
2 S							1									1			1		
2 N	1	3		1	2	1							1	1		3	6	1	3	6	1
3 S																					
3 N																					
4 S	2	4	2	3	3	1									1	5	7	4	5	7	4
4 N	3	7		8	7	1							1	2	1	11	15	2	12	16	2
5 S	2	2	2	4	8	4							5	6	6	10	12	10	11	16	12
5 N	12	13	6	21	18	2							3	8	2	32	35	10	36	39	10
6 S																					
6 N													1			1			1		
7 S																					
7 N																					
8 S		2			5								1			1	7		1	7	
8 N																					
9 S	3	1	1	7	3	3							1	2		10	5	3	11	6	4
9 N																					
10 S				1										1		1	1		1	1	
10 N	1			1	2											2	2		2	2	
11 S						1												1			1
11 N	5	5		7	6					1	1		2	3		14	14		15	15	
12 S																					
12 N																					
13 S																					
13 N																					
14 S																					
14 N																					
15 S																		1			1
15 N						1									1			1			1
Total	42	47	17	59	56	15	1	0	0	1	1	0	15	24	13						
Provincial Total																108	116	41	118	128	45

*Upper Cretaceous Includes: Basal Colorado, Viking, Bow Island, Cadotte, Peace River and Cardium.

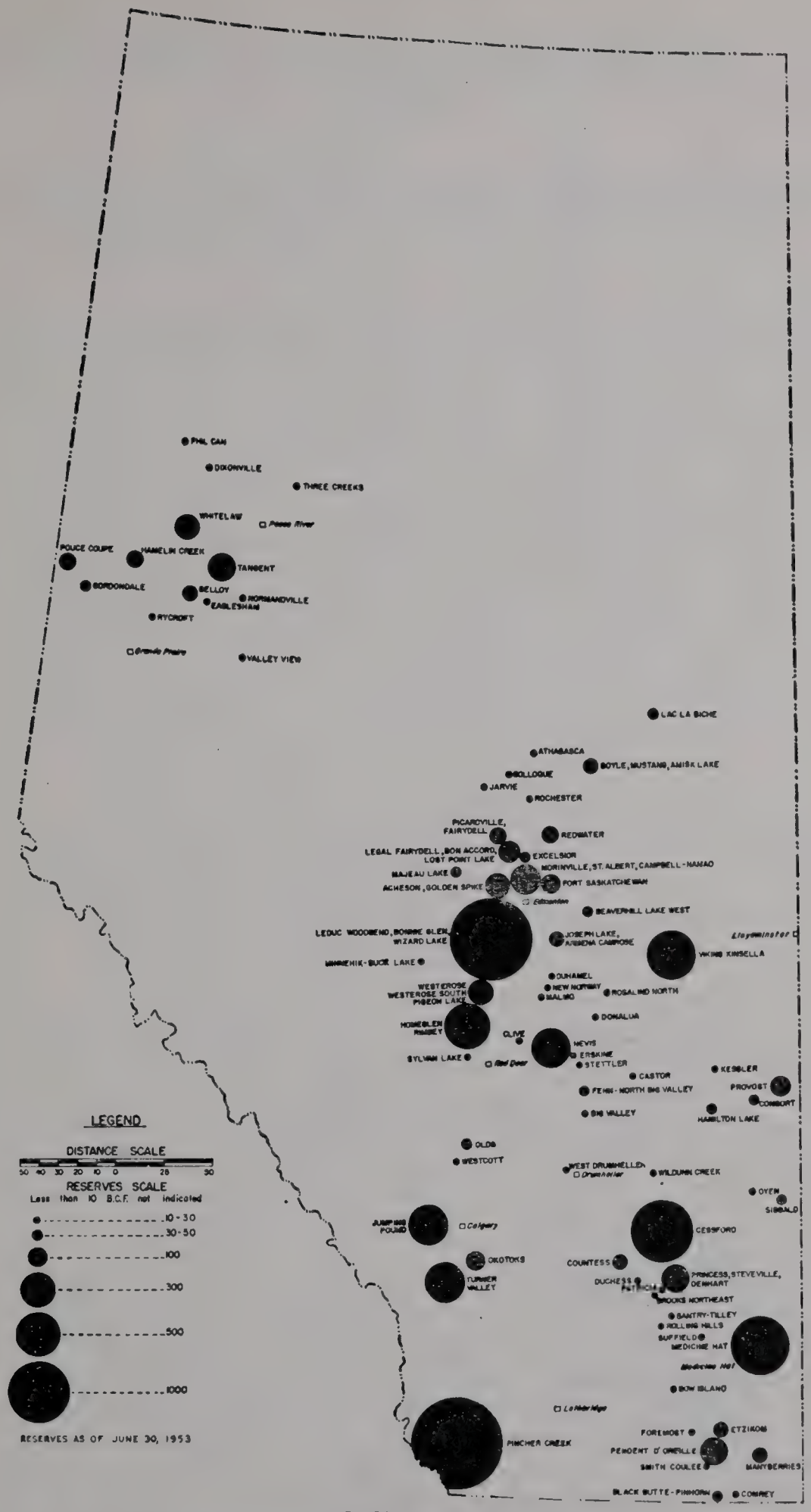


FIGURE A-1

LOCATION AND RELATIVE MAGNITUDE OF THE
ESTABLISHED DISPOSABLE RESERVES OF NATURAL GAS

PROVINCE OF ALBERTA

THE PETROLEUM AND NATURAL GAS CONSERVATION BOARD

NOVEMBER, 1953

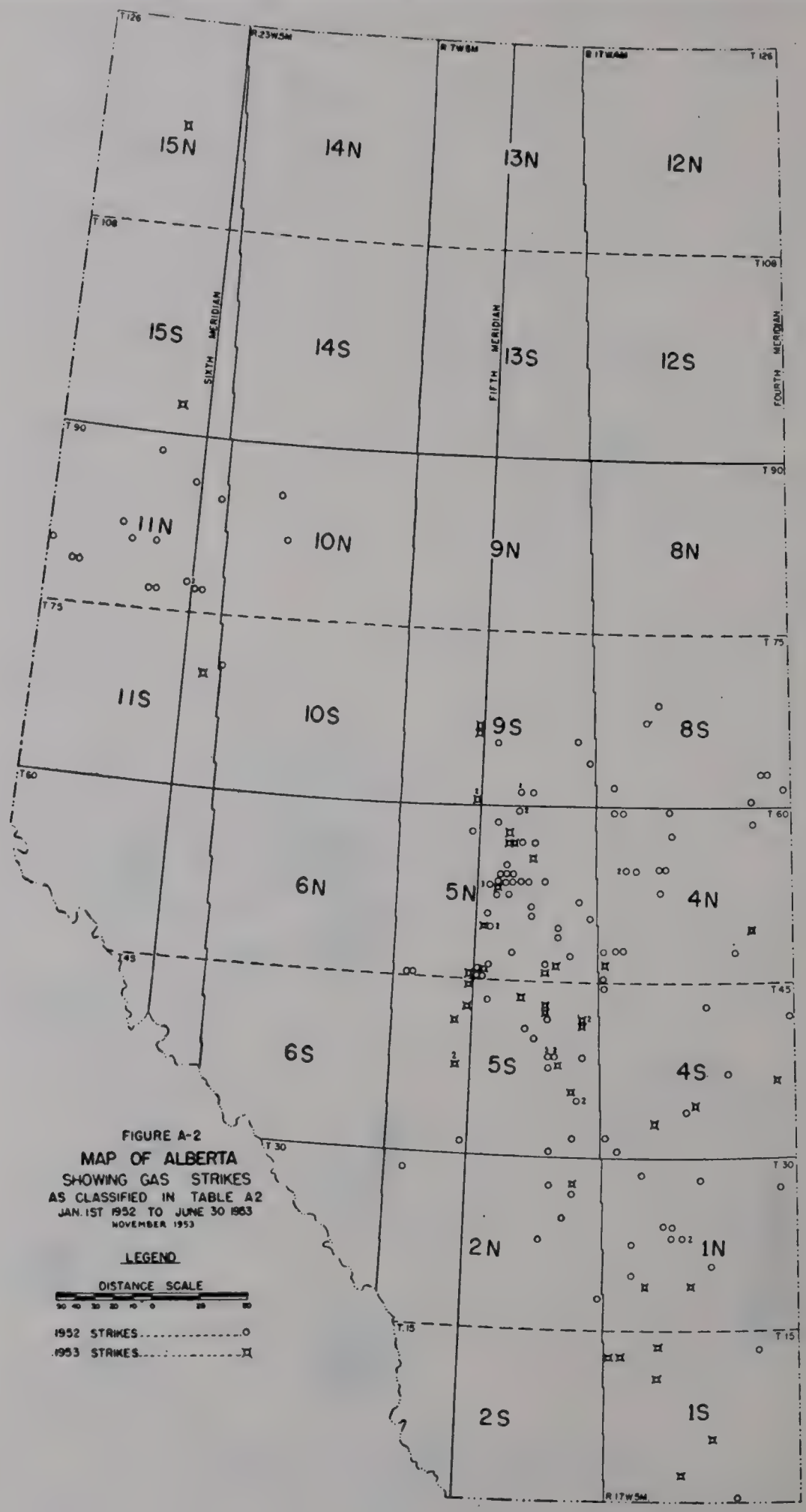


FIGURE A-2

MAP OF ALBERTA

SHOWING GAS STRIKES

AS CLASSIFIED IN TABLE A2

JAN. 1ST 1952 TO JUNE 30 1953

NOVEMBER 1953

LEGEND

DISTANCE SCALE

50 40 30 20 10 0 20 40

1952 STRIKES.....o

1953 STRIKES.....

APPENDIX B

IN THE MATTER OF THE TRENDS IN EXPLORATION AND THE GROWTH OF RESERVES OF NATURAL GAS IN THE PROVINCE OF ALBERTA

In its report of March 1952, the Board presented a study of the trends in Exploration and Growth of Reserves. Statistics available and analyzed at that time indicated to the Board "that 4.0 billion cubic feet of new gas reserves per wildcat drilled is a realistic interpretation of what can be expected per wildcat drilled at the present time". Further it was stated that "Even assuming that the average figure of 4.0 billion cubic feet per wildcat should decrease to 2.0 billion cubic feet per wildcat for a further 4,500 wildcats, a gain in initial reserves of disposable gas of some 9 trillion cubic feet is indicated. Again, at an exploration rate of 500 wildcats per year, new reserves of one trillion cubic feet per year might reasonably be expected for some years". Thus the Board came to its conclusion namely that "with a continued incentive for exploration for oil and gas resulting in the drilling of some 400 - 500 wildcat wells per year, the Province of Alberta can safely anticipate the development of further established reserves of natural gas at an average rate of at least one trillion cubic feet per year for at least the next 8 - 10 years". The Board then, as now, was concerned with a safe, average rate upon which the Province could depend.

The Board was pleased to receive testimony that the recent discoveries have been at a rate in excess of its predicted "safe, average 10-year rate". The evidence of witnesses for the applicants has been studied in the light of the Board's own statistical and other records and adjusted to be consistent with the Board's reserve estimates. The Board has in fact reviewed the entire question of the "Trends".

Evidence was submitted by Messrs. Trostel and Gussow that there are over 200,000 square miles of potential gas lands in the Province. This is some 65,000 square miles above the figure used by the Board in its March 1952 report. The 200,000 figure includes all the area covered by sediments to a depth in excess of 1,000 feet thick but does not include the mountains and the large lake areas. With the inclusion of the tundra region, which may be explored during favorable seasons, the Board's geologist accepts the area of 200,000 square miles as being more realistic than the Board's previous figure. The Board also accepts this new figure.

Various witnesses made reference to the rate of growth of reserves as reflected by the December, 1950 and the December, 1951 estimates of the Board of 4.7 and 6.8 TCF respectively. These figures indicate a "growth" of some 2.1 TCF per year. The present estimate of 11.5 TCF shows a growth since January 1, 1952 at the rate of 3.1 TCF per year. The growth over a period January 1, 1950 to June 30, 1953 is at an average rate of 2.7 TCF per year. Certainly the one trillion cubic feet per year figure has been "safe" for the past two and one-half years and especially so when one bears in mind the fact that the reserves discovered in the last 3 or 4 years are still not fully evaluated and will undoubtedly be rated higher after further development.

Statistical data dealing with wildcat wells drilled and initial gas reserves discovered to June, 1953 are presented in Table B-1 which is a revision of the corresponding table of the March 1952 report. These data show that at June 30, 1953, the drilling of 2,295 wildcat wells had resulted in the discovery of some 12.1 trillion cubic feet of initial disposable gas reserves. This is at an overall discovery rate of 5.3 billion cubic feet of gas for every wildcat well drilled. (Compare with 4.5 billion cubic feet per wildcat well indicated in the March 1952 report.)

Mr. Hawthorn presented testimony related to the success ratio of recent wildcat wells. He defined as a successful wildcat well any wildcat well discovering a commercial reserve of oil or gas. While this takes no account of the size of the "strike" the trend of such successes or failures is a useful indicator. Figure B-1, which indicates the total and the successful wildcat wells drilled each year, is a revision of that presented by Mr. Hawthorn to reflect Board statistics. The increasing success ratio since 1941 and the present high ratio of some 30 per cent are both significant. Dr. Gussow also gave testimony which has a bearing on the trend of the success ratio and his expectations for the future. He pointed out the limited number of exploratory wells which have penetrated the Rundle, Devonian and deeper sections and the great prospects of these sections. This could be interpreted as an indication that the present high success ratio would be maintained, or even improved, over the next decade through increasing exploration of these deep horizons.

The evidence of Figure B-1 coupled with competent opinion, such as that of Dr. Gussow, does suggest optimism on the matter of success ratio. The Board, however, cannot safely assume that the present high ratio will be fully maintained for the next decade. Also, having in mind the size of the strikes, the Board holds to its previously expressed opinion that, on the average, the returns per unit of exploratory effort will tend to diminish. The difficult question is how soon this may occur. The Board's best judgment on this matter is presented later.

The growth of the reserves over the years is illustrated in Figure B-2. Both the Board's present estimate and its March 1952 estimate (as of December 31, 1951) are reflected in this figure. The need for a three to four year time lag to fully evaluate new reserves is apparent. This figure illustrates that the discoveries made prior to 1948 were almost fully evaluated in the Board's December 1951 estimate but that reserves discovered in 1949, 1950 and 1951 were underestimated on the basis of present knowledge. It may be concluded that the present estimate of reserves discovered in 1949 is a nearly full evaluation but that the present estimates for reserves discovered subsequent to 1949 are likely on the low side.

Figure B-3 was developed to indicate the trend in initial disposable reserves per wildcat well drilled. The dashed line AA represents the initial disposable reserves discovered for each wildcat well drilled during the year. This is an erratic line from which it is difficult to develop a trend. Line BB indicates the trend in the initial cumulative disposable reserves discovered per cumulative number of wildcat wells drilled. The overall cumulative figure to June 30, 1953 is shown as 5.3 BCF per wildcat well—the same figure mentioned earlier. It is to be noted that the corresponding figure to the end of 1951 is 6.3 BCF, the figure to the end of 1950 is 7.4 BCF and

the figure to the end of 1949 is 8.6 BCF. Having in mind the time lag demonstrated in Figure B-2 the Board believes that it can consider a figure of 6 billion cubic feet per wildcat well to be a realistic interpretation of what can be expected per wildcat well drilled at the present time.

Figure B-4 has been prepared to illustrate the trend in growth of initial disposable reserves with the cumulative number of wildcat wells drilled. This figure is the counterpart of Figure B-1 of the March 1952 Report and is based on the data of Table B-1.

The line AB is the best fit straight line (through the data from 1950 on) and reflects the 1950 cumulative discovery rate of 7.4 BCF per wildcat well. The dotted extension of this line BC is a possible forecast of what future wildcat wells might bring in the way of new reserves. This extension is based on the assumptions—

(a) that future development of recent discoveries will increase the cumulative reserves to June 30, 1953 to a figure near 17 TCF;

(b) that a further 1,500 or so wildcat wells will on the average give rise to increases at a rate near 7.4 BCF per wildcat well; and

(c) that, after the drilling of a total of some 4,000 wildcat wells, the new reserves discovered per wildcat well will decrease, becoming negligible after the drilling of a total of some 20,000 wildcat wells. (The figure of 20,000 wildcat wells is consistent with one wildcat well per 10 square miles for a total of 200,000 square miles.)

While recognizing the realism of this projection from many points of view the Board cannot advocate it as one the Province of Alberta can safely anticipate.

All things considered the Board presents line DEF as a conservative and safe interpretation and extrapolation. To the drilling of some 3,500 wildcat wells this line is consistent with a present discovery rate of 6.0 BCF per wildcat well—being near the 1951 rate. For further drilling the line reflects a decreasing discovery rate. Even this projection, however, suggests initial reserves of over 35 TCF after the drilling of 10,000 wildcat wells compared with the 20 TCF figure in the March 1952 Report.

After the experience of the last year and a half, and in the view of the testimony of competent geologists and engineers, the Board is now prepared to revise its previous opinion as to the average growth rate which the Province may safely anticipate. Making the conservative assumption that the present figure of 6.0 BCF per wildcat well should decrease to an average of 3 BCF for the drilling of a further 4,000 wildcat wells, a gain in initial reserves of some 12 TCF is indicated. Further, the drilling of 400 - 500 wildcat wells per year, would bring about reserve increases of the order of 1.2 to 1.5 TCF per year.

The Board therefore concludes that, with a continued incentive for exploration for oil and gas resulting in the drilling of 400 - 500 wildcat wells per year, the Province of Alberta can safely anticipate the development of further established reserves of natural gas at an average rate of one and one-quarter to one and one-half trillion cubic feet per year for the next 8 to 10 years.

Table B-1

The Petroleum and Natural Gas Conservation Board

TRENDS IN WILDCAT DRILLING AND GROWTH OF DISPOSABLE GAS RESERVES IN THE PROVINCE OF ALBERTA

1	2	3	4	5	6	7	8
Year	Wildcat Wells Per Year	Wildcat Wells Cumulative	Name of Field	Disposable Gas Reserves as of June 30, 1953, Mmmcf.	Sales to Dec. 31, 1952 Mmmcf.	Disposable Gas Reserves at Date of Discovery Mmmcf.	Cumulative Disposable Gas Reserves at Date of Discovery Mmmcf.
Prior to 1930		172	Medicine Hat, Bow Island, Brooks, Tilley, Castor, Viking-Kinsella, Turner Valley, Foremost, Pouce Coupe	1955	623	2578	2578
1930	29	201					2578
1931	9	210					2578
1932	6	216					2578
1933	7	223					2578
1934	3	226	Lloydminster	7	2	9	2587
1935	2	228					2587
1936	8	236					2587
1937	15	251	Battleview, Vermilion	6	4	10	2597
1938	12	263					2597
1939	18	281					2597
1940	23	304	Princess, Denhart, Steveville	175		175	2772
1941	20	324	Suffield	19	1	20	2792
1942	43	367	Bantry, Tilley, Oyen Jenner	31	1	32	2824
1943	34	401	Athabasca	7		7	2831
1944	56	457	Black Butte, Pinhorn, Jumping Pound	45 375	1 11	46 386	3263
1945	56	513	Patricia	10		10	3273
1946	54	567	Beaverhill Lake	30		30	3602
			Lindbergh	8		8	
			Pendent D'Orielle	175	6	181	
			Provost	94		94	
			Other Fields	16		16	

1947	71	638	Dunmore (Ellis)	15		15	4679
			Hanna	8		8	
			Leduc-Woodbend	841	10	851	
			Legal, Fairydell	60		60	
			Mannyberries	65		65	
			Picardville-Fairydell	65		65	
			Smith Coulee	10		10	
			St. Paul	3		3	
1948	126	764	Morinville	122		122	6892
			Pincher Creek	2000		2000	
			Redwater	73		73	
			Other Small Fields	18		18	
1949	209	973	Ashmont	10		10	8405
			Bolloque Lake	12		12	
			Bon Accord, Lost Point Lake	45		45	
			Boyle, Mustang, Amisk Lake	50		50	
			Campbell, Namao	40		40	
			Castor	20		20	
			Cessford, Sunnynook	965		965	
			Steveville			34	
			Excelsior	34		131	
			Golden Spike	131		65	
			Joseph Lake, Armena-Camrose	65		40	
			Lac La Biche	40		10	
			Normandville	10		18	
			Stettler	18		28	
			Rochester	28		45	
			Other Small Fields	45			
1950	224	1197	Acheson	83		83	8829
			Big Valley	10		10	
			Countess	60		60	
			Duhamel	18		18	
			Jarvie	10		10	
			Rolling Hills	10		10	
			Sibbald	30		30	
			Valleyview	13		13	
			Whitelaw	140		140	
			Other Small Fields	50		50	
1951	456	1653	Belloy	60		60	10491
			Big Valley, North and Fenn	35		35	
			Bonnie Glen	744		744	
			Clive	15		15	

Table B-1 (Continued)

1	2	3	4	5	6	7	8
Year	Wildcat Wells Per Year	Wildcat Wells Cumulative	Name of Field	Disposable Gas Reserves as of June 30, 1953 Mmmcf.	Sales to Dec. 31, 1952 Mmmcf.	Disposable Gas Reserves at Date of Discovery Mmmcf.	Cumulative Disposable Gas Reserves at Date of Discovery Mmmcf.
1951	456	1653	Duchess	13		13	
			Etzikom	60		60	
			Fort Saskatchewan	100		100	
			Hamelin Creek	75		75	
			Majeau Lake	38		38	
			New Norway	10		10	
			Okotoks	100		100	
			St. Albert	62		62	
			Tangent	165		165	
			Westcott	15		15	
			Wizard Lake	96		96	
			Other Small Fields	74		74	
1952	459	2112	Comrey	11		11	11493
			Consort	40		40	
			Dixonville	27		27	
			Donalda	10		10	
			Eaglesham	13		13	
			Erskine	10		10	
			Gordondale	36		36	
			Hamilton Lake	40		40	
			Malmo	20		20	
			Minnehik, Buck Lake	20		20	
			Nevis	390		390	
			Olds	40		40	
			Pigeon Lake	10		10	
			Rycroft	12		12	
			West Drumheller	19		19	
			Westerose	130		130	
			Wildunn Creek	15		15	
			Other Small Fields	159		159	
1953	183	2295	Homeglen, Rimbey	500		500	12111
			Sylvan Lake	25		25	
			Westerose South	30		30	
			Other Small Fields	63		63	

NUMBER OF WILDCAT WELLS DRILLED EACH YEAR

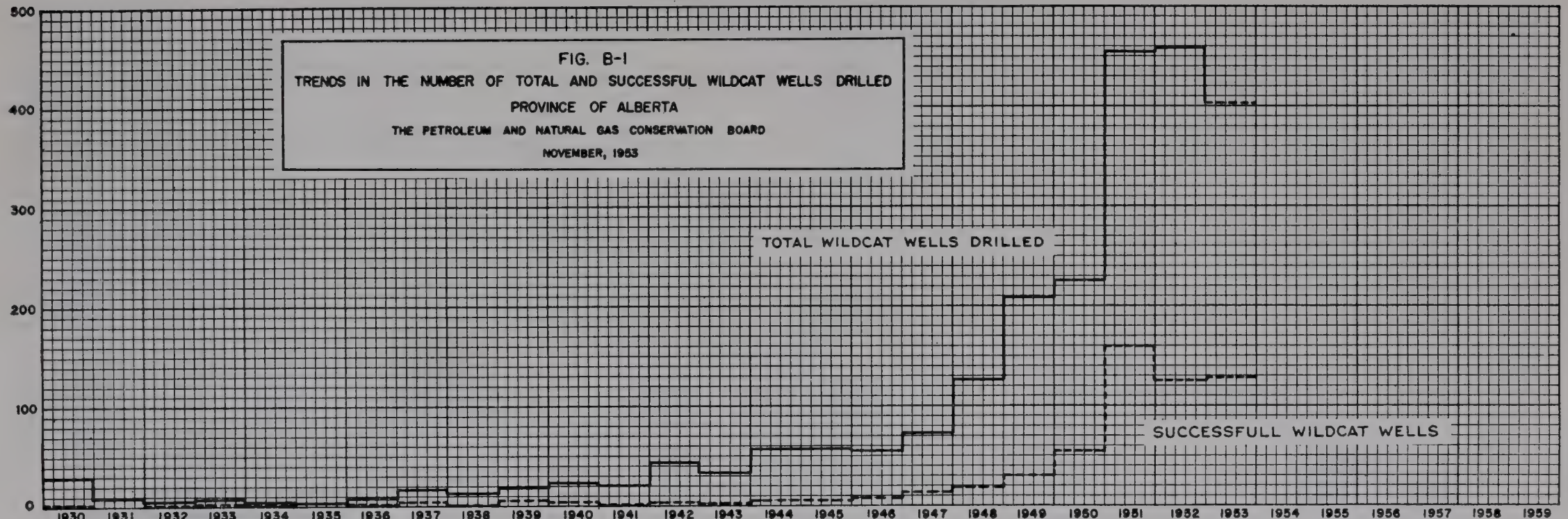
FIG. B-1

TRENDS IN THE NUMBER OF TOTAL AND SUCCESSFUL WILDCAT WELLS DRILLED

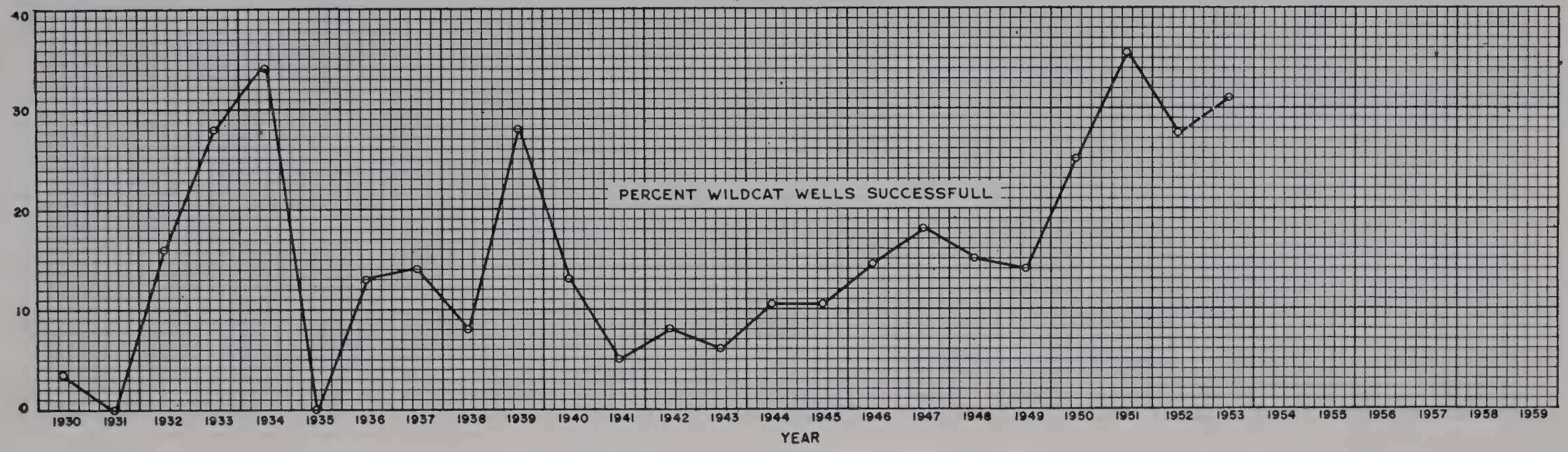
PROVINCE OF ALBERTA

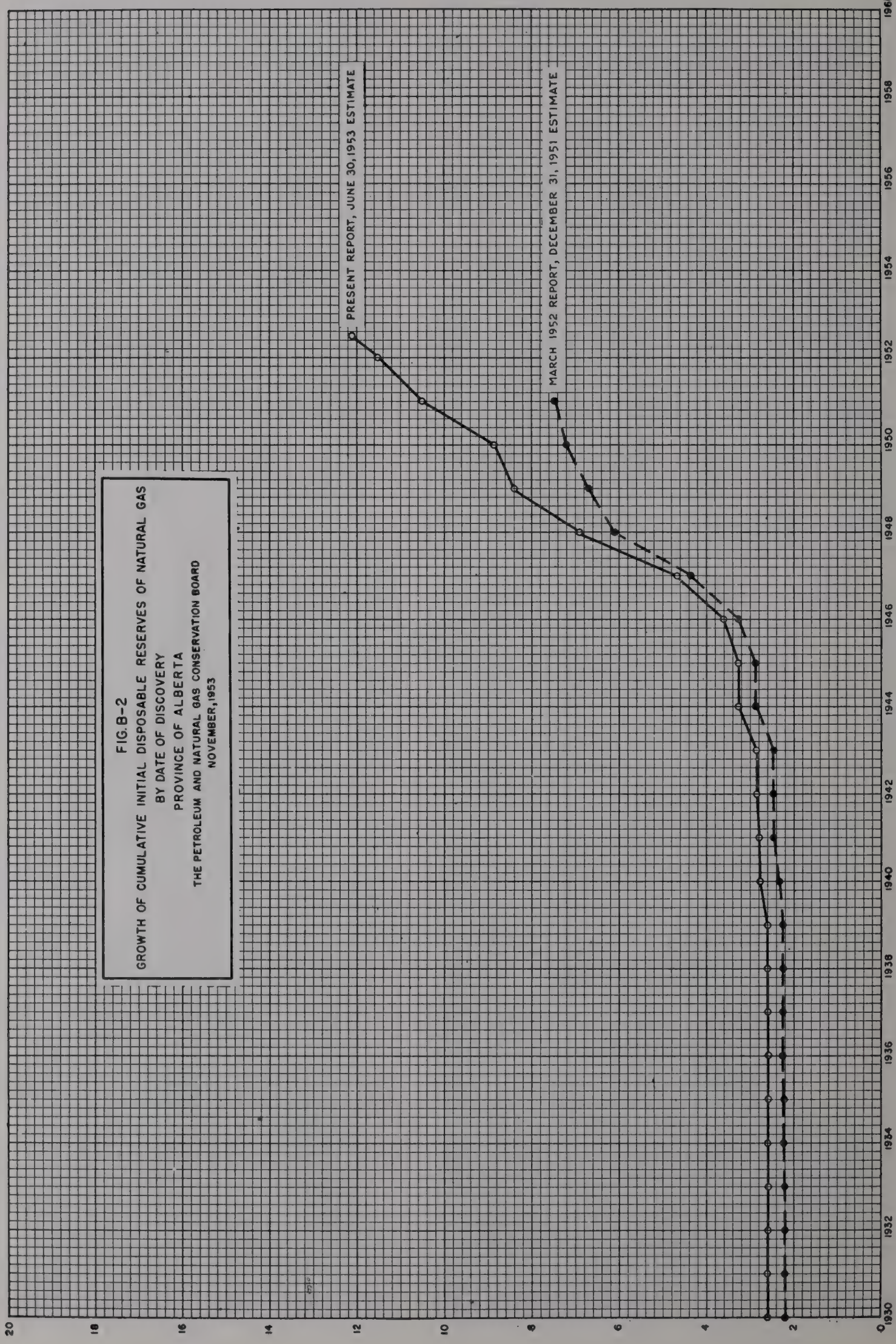
THE PETROLEUM AND NATURAL GAS CONSERVATION BOARD

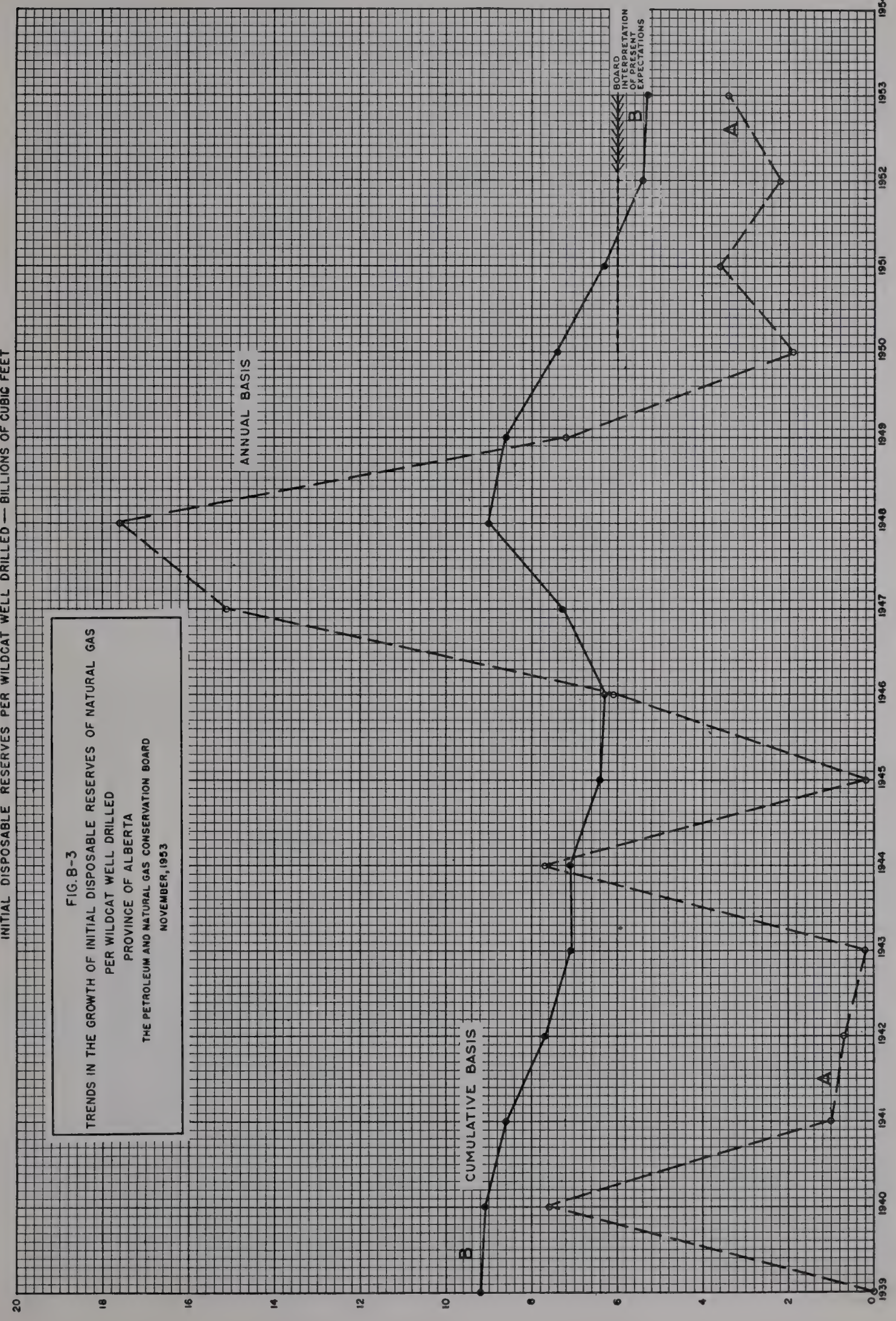
NOVEMBER, 1953



PERCENT SUCCESSES




PRESENT REPORT, JUNE 30, 1953 ESTIMATE
MARCH 1952 REPORT, DECEMBER 31, 1951 ESTIMATE
FIG. B-2
GROWTH OF CUMULATIVE INITIAL DISPOSABLE RESERVES OF NATURAL GAS
BY DATE OF DISCOVERY
PROVINCE OF ALBERTA
THE PETROLEUM AND NATURAL GAS CONSERVATION BOARD
NOVEMBER, 1953
0
2
4
6
8
10
12
14
16
18
20
1930
1932
1934
1936
1938
1940
1942
1944
1946
1948
1950
1952
1954
1956
1958
1960
DATE OF DISCOVERY


INITIAL DISPOSABLE RESERVES PER WILDCAT WELL DRILLED — BILLIONS OF CUBIC FEET
20
18
16
14
12
10
8
6
4
2
0
1939
1940
1941
1942
1943
1944
1945
1946
1947
1948
1949
1950
1951
1952
1953
1954
YEAR
ANNUAL BASIS
CUMULATIVE BASIS
A
B
BOARD INTERPRETATION OF PRESENT EXPECTATIONS
FIG. B-3
TRENDS IN THE GROWTH OF INITIAL DISPOSABLE RESERVES OF NATURAL GAS PER WILDCAT WELL DRILLED
PROVINCE OF ALBERTA
THE PETROLEUM AND NATURAL GAS CONSERVATION BOARD
NOVEMBER, 1953

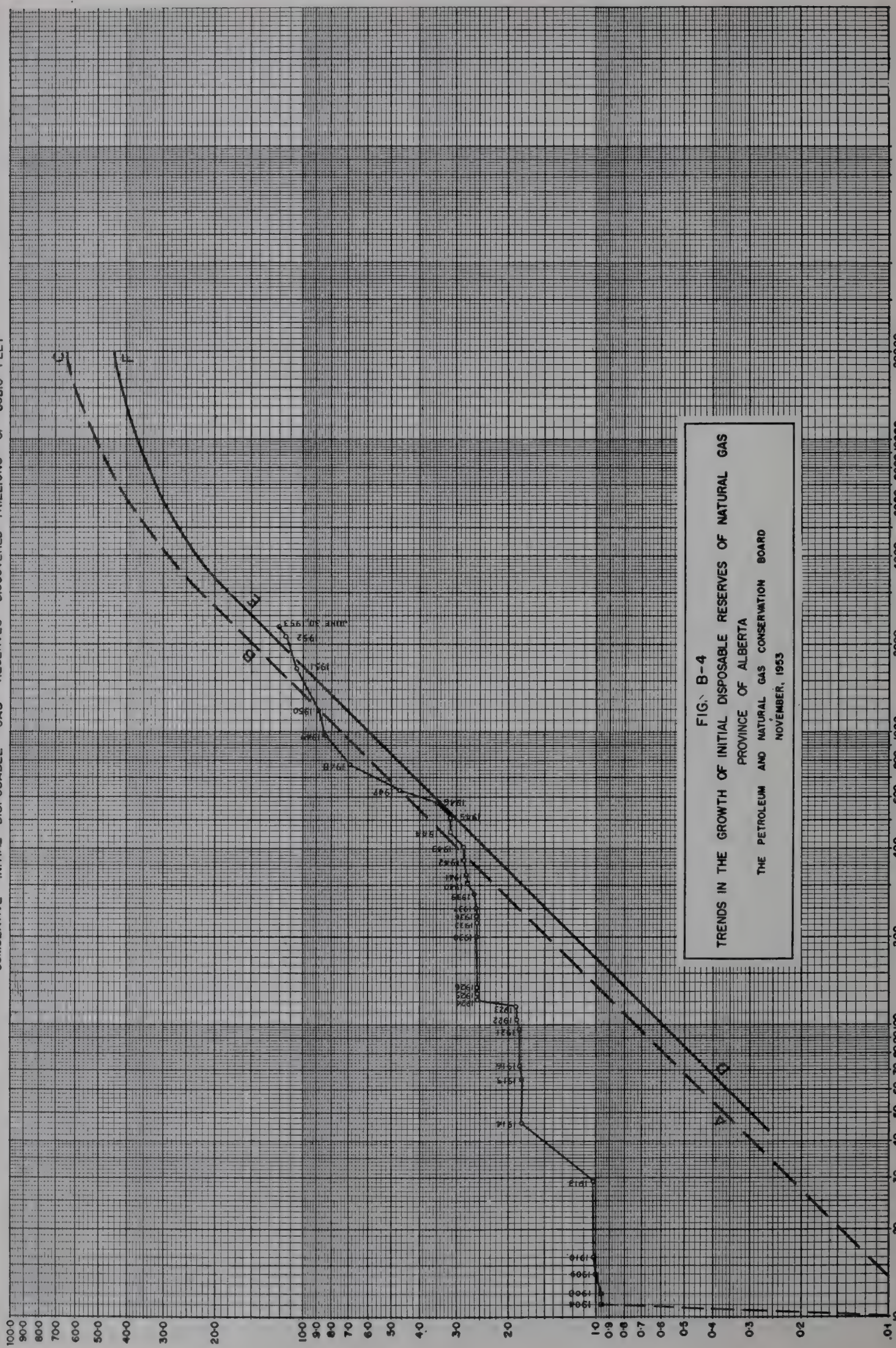


FIG. B-4

TRENDS IN THE GROWTH OF INITIAL DISPOSABLE RESERVES OF NATURAL GAS
PROVINCE OF ALBERTA
THE PETROLEUM AND NATURAL GAS CONSERVATION BOARD
NOVEMBER, 1953

APPENDIX C

PRESENT AND FUTURE REQUIREMENTS OF THE PROVINCE

Briefs regarding estimated future provincial requirements were submitted by Trans-Canada Pipe Lines Limited, et al, by the Canadian Western Natural Gas Company Limited and Northwestern Utilities, Limited, and by the Alberta Power Commission.

Estimates of Trans-Canada Pipe Lines Limited et al

Mr. Harries, on behalf of Trans-Canada, presented a submission which supplemented and amended his comprehensive 1951 study in the "light of new facts which the past two years have made available". The same basic methodology was used in the two studies.

Domestic and Commercial Requirements

Mr. Harries again estimated domestic and commercial requirements by combining per capita consumption rates and population projections. In some instances the 1951 population estimates have been revised in order to conform with the 1951 census. The per capita consumption rates were, however, left unaltered.

These revised population projections have provided an increase in estimated requirements. Mr. Harries estimates are less than those of the Board due largely to the much more conservative attitude taken by him towards population growth. A comparison of his 1951 and 1953 estimates follows, expressed in billions of cubic feet.

Comparison of Domestic and Commercial Requirements as Estimated by Mr. Harries in 1951 and 1953

Annual Requirements	1951	1953
1954	37.9	39.7
1960	49.8	52.5
1970	57.7	68.2
1980	64.2	80.2
Total Requirements for 30 Years		
1951 - 1980	1,568.1	
1954 - 1983		1,941.0

Rural Electrification

In his 1951 study Mr. Harries made a very detailed survey to determine the number of potential power users which, in his opinion, would be served by local generating plants using natural gas for fuel. In his new submission he has not made

provision for this type of consumption in view of the fact that "During the past two years there has been no indication that the suggestion appealed to power companies or to particular farm areas".

Industrial

Mr. Harries has again divided industrial requirements into the following three categories:

1. Ordinary Industrial
2. Electrical Power Generation
3. Major Industrial

Estimates of ordinary industrial requirements were based on the revised population study together with a per capita rate of 8 MCF. In 1951 he used a higher per capita rate of 10 MCF. The effect of changes in both variables is a slight decrease in estimated requirements.

Mr. Harries has not altered his previous estimated requirements for electrical power generation. He has, however, made revisions to major industrial requirements which reflect "a significant increase in the projected use of natural gas for industrial purposes".

A comparison of the total industrial requirements for the two studies is provided below, expressed in billions of cubic feet.

Comparison of Industrial Requirements as Estmated by Mr. Harries in 1951 and 1953

Annual Requirements	1951*	1953
1954	32.8	39.9
1960	56.3	60.3
1970	69.6	72.9
1980	80.1	83.2
Total Requirements for 30 Years		
1951 - 1980	1,790.0	
1954 - 1983		2,075.1

*Includes estimates for Rural Electrification Requirements.

Estimates of Canadian Western Natural Gas Company and Northwestern Utilities, Limited

The Canadian Western Natural Gas Company and Northwestern Utilities, Limited submitted a brief providing details of the estimated requirements of the two utility systems for the thirty year period 1953 - 1982. These estimates are considered greater than previous estimates submitted to the Board primarily because of "a marked upward revision of population estimates as a result of the 1951 Dominion Census, and provision

for a substantial amount of additional industrial load". The basic method consisted of estimating the population for each of the systems and applying to "these estimates factors of customers per hundred of population and MCF sales per customer in each of the classes, Domestic, Commercial and Basic Industrial, which factors are projected from past experience". An allowance for special industrial requirements was then added to these estimates.

Domestic and Commercial

Included in the brief were charts showing trends of customers per hundred of population and consumption per customer for each of the consumption classifications. When these factors are reduced to a per capita consumption rate they reveal a rising trend. Mr. Snyder, on behalf of the Companies, reported that in 1953 the combined domestic and commercial consumption per capita for the Calgary system was 76.5 MCF as compared to 81.5 for the Edmonton system. The utility companies estimate that these rates will, by 1962, increase to 83.8 MCF for the Calgary system and 85.6 MCF for the Edmonton system but they will then level out and remain constant.

In discussing this increased saturation, Mr. Snyder, under cross examination, stated, "Part of the reason for the increase in the number of customers served per 100 of the population is that in a great many areas served by the systems there have been considerable numbers of dwellings scattered around inside the distribution system which could not be economically reached by these distribution systems. As the areas have continued to expand and vacant areas have been filled in, we have been able to economically expand our distribution system to pick up not only the new construction but also considerable numbers of those premises that were previously beyond economic reach".

The Canadian Western Natural Gas Company Limited and Northwestern Utilities, Limited now estimate the domestic and commercial requirements for their two systems as follows, expressed in billions of cubic feet.

Canadian Western System, Northwestern Utilities System

Annual Requirements	Domestic	Commercial	Domestic	Commercial
1955	10.5	6.3	11.6	9.3
1960	13.2	7.8	15.1	11.9
1970	16.1	9.6	18.6	14.3
1980	19.7	11.7	22.6	17.1
Total Requirements for 30 Years				
1953 - 1982	458.4	273.1	525.6	406.3

Industrial Requirements

In estimating industrial requirements the utility companies have considered—

(a) Basic Industrial Requirements, and

(b) Special Industrial Requirements,

Basic industrial requirements, that is all industrial requirements other than "the largest loads", have been estimated in the same manner as domestic and commercial. Special industrial requirements comprise the estimated consumption of large load plants presently operating or under construction together with a provision for future additional industrial loads. Although the allowance made for these future loads is of considerable importance it can only be estimated on the basis of judgment.

The estimated total industrial requirements for the two utility systems are provided below, expressed in billions of cubic feet.

Annual Requirements	Canadian Western System	Northwestern Utilities System
1955	13.8	11.5
1960	19.9	21.2
1970	25.7	27.6
1980	27.2	28.5
Total Requirements for 30 Years		
1953 - 1982	686.7	714.9

Brief of the Alberta Power Commission

Estimates of future power development within the Province and anticipated natural gas requirements for the generation of electricity were provided in a brief submitted by the Alberta Power Commission.

Power requirements for the years 1963, 1973 and 1983 were estimated by combining population projections and rates of per capita consumption. The Commission assumed that per capita consumption would increase from the 1952 rate of 1250 K.W.H. to 4600 K.W.H. in 1983. Total power requirements were estimated to increase from 3.1 billion K.W.H. in 1963 to 8.4 billion K.W.H. in 1983.

The brief stressed the difficulty in deciding whether additional requirements would be met from hydro plants, coal-fired plants or gas-fired plants in view of the fact that "the difference in cost of a K.W.H. delivered to the load-consuming areas of the Province from a hydro plant, a coal-fired steam plant, or a gas-fired steam plant, is so small that there is little to choose between them". The Commission stated that in its opinion existing gas-fired plants would install more gas burning units but that steam plants built in new locations would be coal burning and would be located near strip mines.

In 1963 the Commission estimated power requirements at 3.1 billion K.W.H. of which approximately 1.2 billion K.W.H. would be generated by natural gas. It assumed that on the average 15.5 cubic feet of gas would be required to generate one kilowatt hour of electricity rather than the figure of 20 cubic feet used in an earlier brief. The Commission also stated that beyond 1963 they did not anticipate any appreciable increase in the amount of electricity generated by gas.

Estimates of The Petroleum and Natural Gas Conservation Board

In reviewing its 1952 estimates of Alberta requirements, the Board has again employed the same basic methodology. It has taken into consideration the evidence submitted and new information which has been obtained since the last report.

The consumption of natural gas in 1952, exclusive of field and processing plant use and exclusive of propane and butane of "LPG", is indicated in the following table.

	Domestic* BCF	Commercial* BCF	Industrial* BCF	Total BCF
Canadian Western Natural Gas System	8.7	5.4	11.5	25.6
Northwestern Utilities System	9.4	7.5	6.5	23.4
Other (Estimated)	2.0	1.3	5.1	8.4
Total	20.1	14.2	23.1	57.4

This is compared to the Board's 1952 estimate of:

	BCF
Domestic.	20.5
Commercial	13.8
Industrial	26.0
Total	60.3

*Converted to a normal degree day basis.

The estimated industrial requirements for 1952 exceed the actual consumption by 2.9 billion cubic feet which is due to large industrial consumers not completing their plants as early as was expected.

Domestic and Commercial Requirements

The Board does not see any need of revising the population estimates made in 1952. It has again assumed that the urban population will be approximately 60 per cent of the total population by 1960 and that all of the urban population will be served with gas by 1960.

After considering the evidence submitted by the Canadian Western Natural Gas Company Limited and Northwestern Utilities, Limited, the Board has revised the Domestic and Commercial per capita rates (of total population). These rates now increase from 20.8 in 1952 to 29.5 in 1960 for Domestic and from 14.7 in 1952 to 19.5 in 1960 for Commercial.

As indicated in previous reports, the Board is "reluctant to extrapolate the per capita figures beyond 1960. Moreover, it seems to the Board that the present per capita growth may tend to level out within the next decade. Accordingly, the per capita figures are assumed constant from 1960 onward".

Total domestic and commercial requirements for the period 1953 - 1982 are 1,216.7 billion cubic feet and 807.6 billion cubic feet respectively.

Industrial Requirements

Industrial requirements have again been considered under four main categories embracing,

(1) Use of dry or lean natural gas as a fuel for industrial processes, steam generation, power plants, etc.;

(2) Use of dry or lean natural gas, primarily for its methane content, for the manufacture of carbon black, ammonia and a relatively few other products which may be produced economically using methane as a raw material;

(3) Use of ethane recovered from dry wet natural gas for conversion to ethylene and then to other products; and

(4) Use of L.P.G. (propane and/or butanes for conversion by partial oxidation or other processes to a wide range of chemicals; use of butane for conversion to butadiene; use of isobutane for the manufacture of alkylate—important constituent of aviation gasoline.

The Board, in its 1952 report, discussed at some length the anticipated rapid increase that would take place in the industrial demand for natural gas and its related compounds. It drew particular attention to the impact of the two large petrochemical plants of Canadian Chemical Company and Canadian Industries Ltd. as well as to the ore-processing plant of Sherritt Gordon Mines Ltd.

Since the completion of the 1952 report, the Board has had the opportunity to examine additional evidence. Information has been received regarding new expansion programs for existing plants together with plans for establishing new industries within the Province. In addition, a reassessment has been made of the anticipated future growth of the petrochemical industry which leads the Board to believe that considerable expansion can be expected.

The best yardstick for forecasting these industrial requirements is, in the Board's opinion, by per capita consumption rates (of the total population) related to past trends but adjusted to take into consideration current information together with an allowance for future expansion. The Board has reviewed the per capita rates used in the 1952 report, and, in view of the evidence submitted and further information obtained, has made a small upward revision. It has been assumed that the per capita industrial rate will rise sharply within the next few years but will level off about 1960 at a rate of 59 MCF as compared to 24.0 MCF in 1952. This corresponds to an annual per capita increase of 11.9 per cent for the eight year period. The 1952 report estimate of 56 MCF per capita in 1960 represented an average annual increase of 9.7 per cent from 1951 to 1960.

In accordance with previous practice, an allowance has been made for fuel consumed in gas processing plants in fields such as Turner Valley, Leduc-Woodbend and

Jumping Pound in the "Surface Discount Factor" applied to the producible gas from these fields in order to determine the disposable gas figure for each field.

Revised Projections

Figure C-2 contains the revised trends in per capita consumption for domestic, commercial and industrial requirements. The total annual requirements under each of these categories is obtained by combining the per capita rate with the population projection of Figure C-1. These requirements are shown graphically in Figure C-3 and in tabular form in Table C-1. Figure C-4 compares Mr. Harries' estimate with that of the Board.

The Board now estimates the requirements of the Province for the thirty year period 1953 - 1982 as 4,445.3 billion cubic feet. A comparison with the 1952 report is provided below.

	Report March 29, 1952 (Period 1952-1981) Billion Cubic Feet	Revised (Period 1953-1982) Billion Cubic Feet
Domestic	1,114.7	1,216.7
Commercial	763.5	807.6
Industrial	2,248.7	2,421.0
Total	4,126.9	4,445.3

These requirements are allocated to the areas tributary to the Canadian Western Natural Gas Company Limited system, the Northwestern Utilities, Limited system, the Medicine Hat Redcliffe area, the Peace River area and the remainder of the Province as shown in Table C-2. This table contains the estimated peak day requirements and the load factors for the five areas. As pointed out in the previous reports any allocation of requirements as between areas of the Province and any estimates of future load factors must be somewhat arbitrary. The present allocation and estimates represent the Board's best judgment in the matter.

The estimated requirements of the area tributary to the Northwestern Utilities, Limited system have been increased by 241.8 billion cubic feet over the estimate of the 1952 report and now amount to 2,327.7 billion cubic feet. The total for the area tributary to the Canadian Western System has been increased by 52.5 billion cubic feet. These requirements are now estimated at 1,350.7 billion cubic feet. In this report the remaining provincial requirements have been allocated to the Medicine Hat-Redcliffe area, the Peace River area and the remainder of the Province. The total estimated requirements for this group have been increased by 24.1 billion cubic feet and now total 766.9 billion cubic feet.

Table C-I

The Petroleum and Natural Gas Conservation Board

ESTIMATE OF NATURAL GAS REQUIREMENTS

Province of Alberta, January 1, 1953 - December 31, 1982

(Corresponds with the projections of Figure C-3)

1	2	3	4	5
Year	DOMESTIC Billions of cubic feet	COMMERCIAL Billions of cubic feet	INDUSTRIAL Billions of cubic feet	TOTAL Billions of cubic feet
1953	22.4	15.2	29.3	66.9
1954	24.3	16.5	46.0	86.8
1955	26.3	17.8	52.7	96.8
1956	28.4	19.2	57.5	105.1
1957	30.2	20.7	62.6	113.5
1958	32.0	21.6	65.6	119.2
1959	33.9	22.7	68.8	125.4
1960	36.0	23.8	72.0	131.8
1961	36.7	24.3	73.5	134.5
1962	37.5	24.8	74.9	137.2
1963	38.2	25.3	76.5	140.0
1964	39.0	25.8	78.0	142.8
1965	39.8	26.3	79.5	145.6
1966	40.6	26.8	81.1	148.5
1967	41.4	27.3	82.7	151.4
1968	42.2	27.9	84.4	154.5
1969	43.0	28.5	86.1	157.6
1970	43.9	29.0	87.8	160.7
1971	44.5	29.4	89.1	163.0
1972	45.2	29.9	90.4	165.5
1973	45.9	30.3	91.8	168.0
1974	46.6	30.8	93.2	170.6
1975	47.3	31.3	94.6	173.2
1976	48.0	31.7	96.0	175.7
1977	48.7	32.2	97.4	178.3
1978	49.4	32.7	98.9	181.0
1979	50.2	33.2	100.4	183.8
1980	50.9	33.7	101.9	186.5
1981	51.7	34.2	103.4	189.3
1982	52.5	34.7	104.9	192.1
Totals	1216.7	807.6	2421.0	4445.3

APPENDIX C

Table C-2

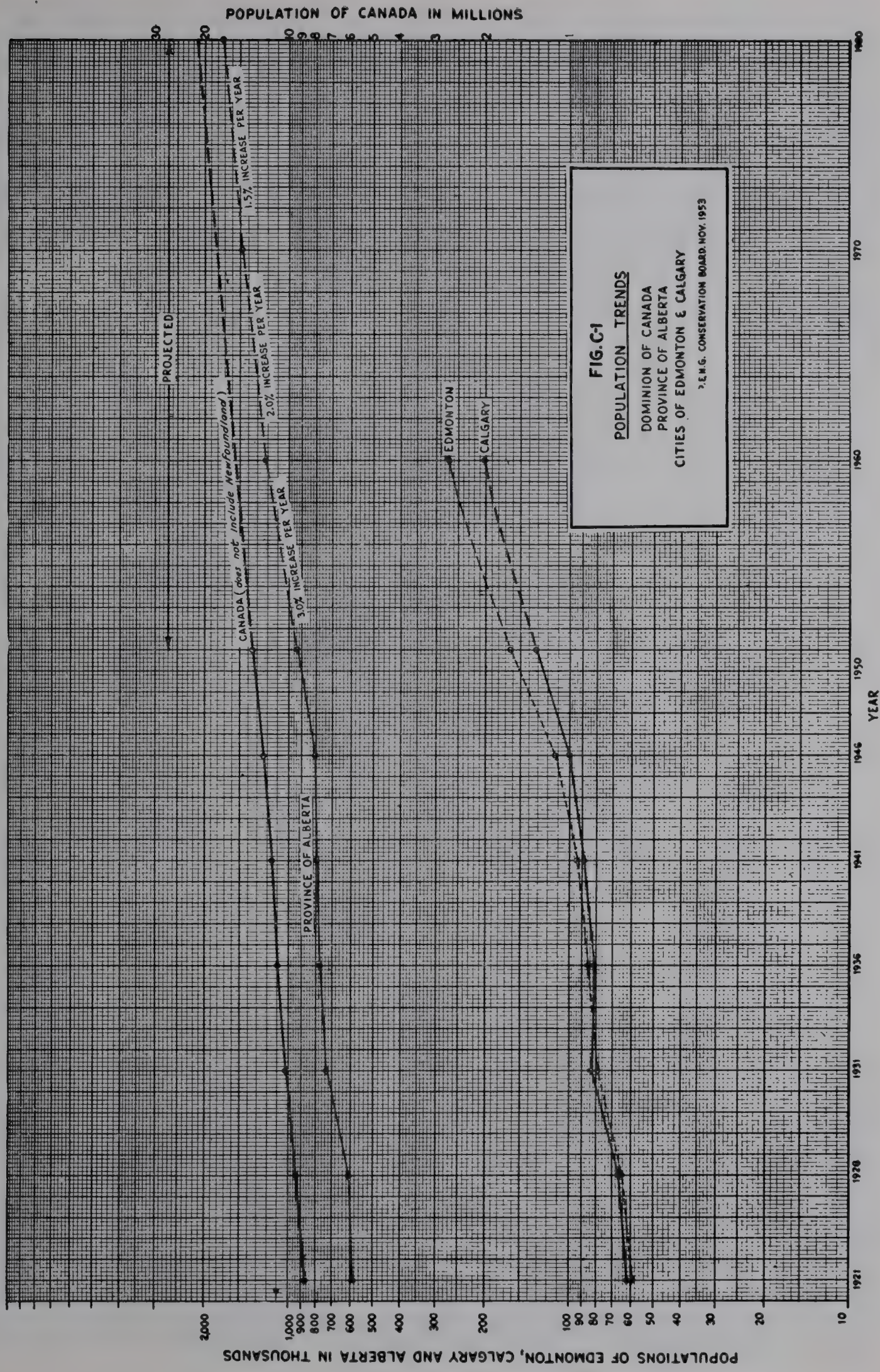
The Petroleum and Natural Gas Conservation Board

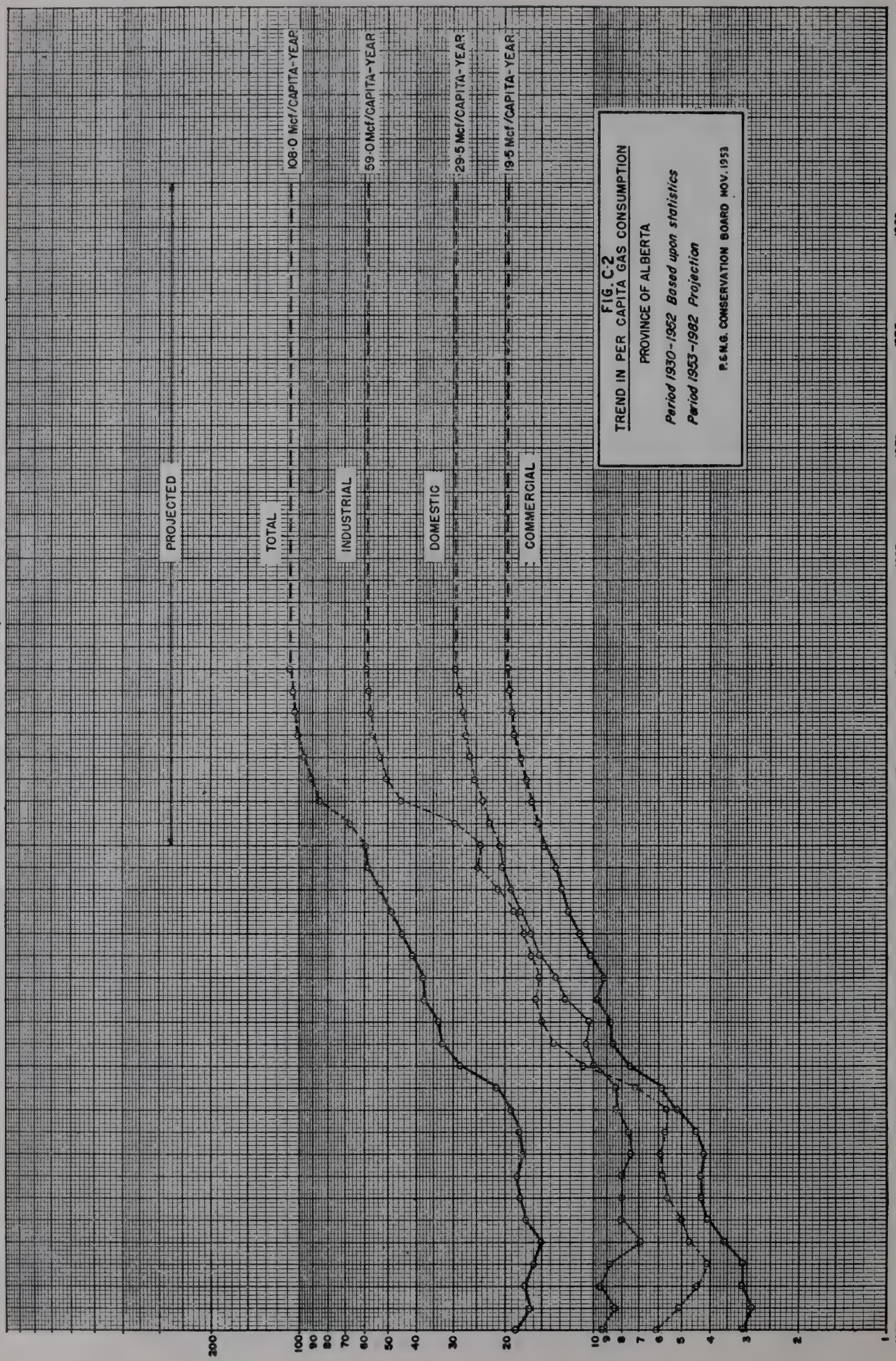
ESTIMATE OF NATURAL GAS REQUIREMENTS

Province of Alberta, January 1, 1953 - December 31, 1982

Allocation Between Areas Tributary to the Distributing Systems

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
	Area tributary to C.W.N.G. system			Area tributary to N.U.L. System			Peace River Area			Medicine Hat - Redcliff Area			Remainder of the Province			Total Provincial Requirements		
Year	Annual billions of cubic feet	Peak Day millions of cubic feet	Load Factor per cent	Annual billions of cubic feet	Peak Day millions of cubic feet	Load Factor per cent	Annual billions of cubic feet	Peak Day millions of cubic feet	Load Factor per cent	Annual billions of cubic feet	Peak Day millions of cubic feet	Load Factor per cent	Annual billions of cubic feet	Peak Day millions of cubic feet	Load Factor per cent	Annual billions of cubic feet	Peak Day millions of cubic feet	Load Factor per cent
1953	27.8	181	42	31.0	189	45	0.3	2	40	5.0	27	50	2.8	19	40	66.9	418	43.8
1954	30.0	196	42	43.6	249	48	0.8	5	40	7.4	37	55	5.0	34	40	86.8	521	45.6
1955	31.6	206	42	50.0	285	48	1.2	8	40	7.7	38	55	6.3	43	40	96.8	580	45.7
1956	33.0	215	42	55.6	311	49	1.6	11	40	7.9	39	55	7.0	48	40	105.1	624	46.1
1957	34.8	227	42	61.1	335	50	2.0	14	40	8.1	40	55	7.5	51	40	113.5	667	46.4
1958	36.4	237	42	64.0	351	50	2.4	16	40	8.3	41	55	8.1	55	40	119.2	700	46.4
1959	37.8	247	42	67.0	367	50	2.8	19	40	8.6	43	55	9.2	63	40	125.4	739	46.4
1960	39.6	258	42	70.2	385	50	3.2	22	40	8.9	44	55	9.9	68	40	131.8	777	46.4
1961	40.7	265	42	71.4	391	50	3.3	23	40	9.0	45	55	10.1	69	40	134.5	793	46.4
1962	41.3	269	42	72.7	398	50	3.4	23	40	9.3	46	55	10.5	72	40	137.2	808	46.4
1963	42.0	274	42	74.2	407	50	3.4	23	40	9.4	47	55	11.0	75	40	140.0	826	46.4
1964	42.8	279	42	75.5	414	50	3.5	24	40	9.7	48	55	11.3	77	40	142.8	842	46.4
1965	43.7	285	42	76.8	421	50	3.7	25	40	9.8	49	55	11.6	79	40	145.6	859	46.4
1966	44.5	290	42	78.3	429	50	3.7	25	40	10.0	50	55	12.0	82	40	148.5	876	46.4
1967	45.4	296	42	79.8	437	50	3.9	27	40	10.2	51	55	12.1	83	40	151.4	894	46.4
1968	46.4	303	42	81.2	445	50	3.9	27	40	10.5	52	55	12.5	86	40	154.5	913	46.4
1969	47.3	309	42	82.8	454	50	4.0	27	40	10.7	53	55	12.8	88	40	157.6	931	46.4
1970	48.3	315	42	84.2	461	50	4.1	28	40	10.8	54	55	13.3	91	40	160.7	949	46.4
1971	48.9	319	42	85.4	468	50	4.1	28	40	11.0	55	55	13.6	93	40	163.0	963	46.4
1972	49.6	324	42	86.6	475	50	4.2	29	40	11.2	56	55	13.9	95	40	165.5	979	46.4
1973	50.4	329	42	87.8	481	50	4.4	30	40	11.3	56	55	14.1	97	40	168.0	993	46.4
1974	51.1	333	42	89.1	488	50	4.5	31	40	11.5	57	55	14.4	99	40	170.6	1008	46.4
1975	51.8	338	42	90.4	495	50	4.5	31	40	11.7	58	55	14.8	101	40	173.2	1023	46.4
1976	52.7	344	42	91.6	502	50	4.6	32	40	11.9	59	55	14.9	102	40	175.7	1039	46.4
1977	53.4	348	42	92.9	509	50	4.6	32	40	12.1	60	55	15.3	105	40	178.3	1054	46.4
1978	54.3	354	42	94.1	516	50	4.7	32	40	12.2	61	55	15.7	108	40	181.0	1071	46.4
1979	55.1	359	42	95.6	524	50	4.8	33	40	12.4	62	55	15.9	109	40	183.8	1087	46.4
1980	55.8	364	42	96.9	531	50	4.9	34	40	12.6	63	55	16.3	112	40	186.5	1104	46.4
1981	56.7	370	42	98.2	538	50	4.9	34	40	12.8	64	55	16.7	114	40	189.3	1120	46.4
1982	57.5	375	42	99.7	546	50	5.1	35	40	12.9	64	55	16.9	116	40	192.1	1136	46.4
Total	1350.7			2327.7			106.5			304.9			355.5			4,445.3		


POPULATION OF CANADA IN MILLIONS
POPULATIONS OF EDMONTON, CALGARY AND ALBERTA IN THOUSANDS
YEAR
PROJECTED
CANADA (does not include Newfoundland)
3.0% INCREASE PER YEAR
2.0% INCREASE PER YEAR
1.5% INCREASE PER YEAR
PROVINCE OF ALBERTA
EDMONTON
CALGARY
FIG.C-1
POPULATION TRENDS
DOMINION OF CANADA
PROVINCE OF ALBERTA
CITIES OF EDMONTON & CALGARY
P.E.N.G. CONSERVATION BOARD NOV. 1953


ANNUAL PER CAPITA GAS CONSUMPTION, THOUSANDS OF CUBIC FEET
200
100
90
80
70
60
50
40
30
20
10
9
8
7
6
5
4
3
2
1
1930
1935
1940
1945
1950
1955
1960
YEAR
PROJECTED
TOTAL
108·0 Mcf/CAPITA-YEAR
INDUSTRIAL
59·0 Mcf/CAPITA-YEAR
DOMESTIC
29·5 Mcf/CAPITA-YEAR
COMMERCIAL
19·5 Mcf/CAPITA-YEAR
FIG. C-2
TREND IN PER CAPITA GAS CONSUMPTION
PROVINCE OF ALBERTA
Period 1930-1952 Based upon statistics
Period 1953-1982 Projection
P.E.N.G. CONSERVATION BOARD NOV. 1953

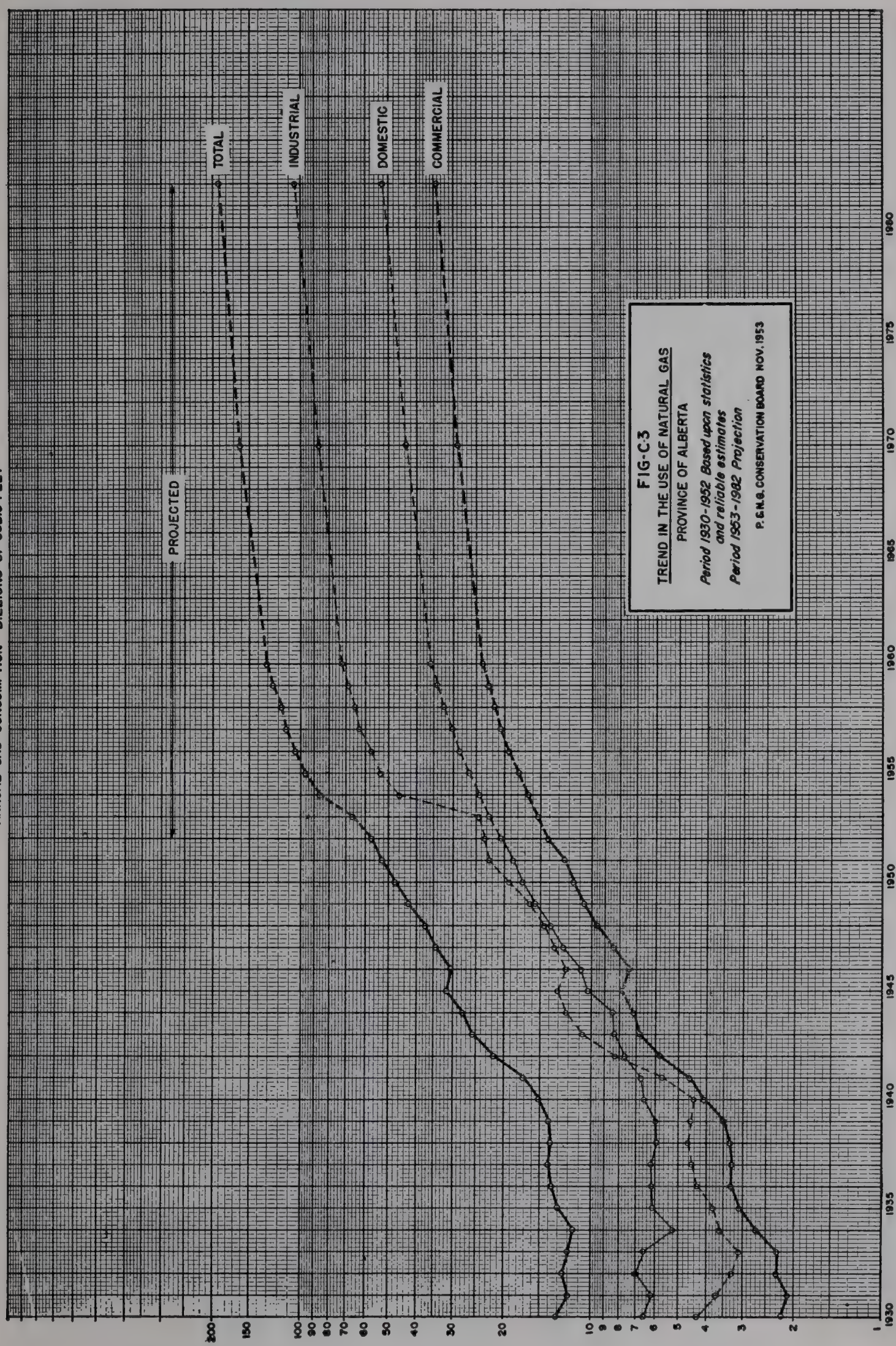
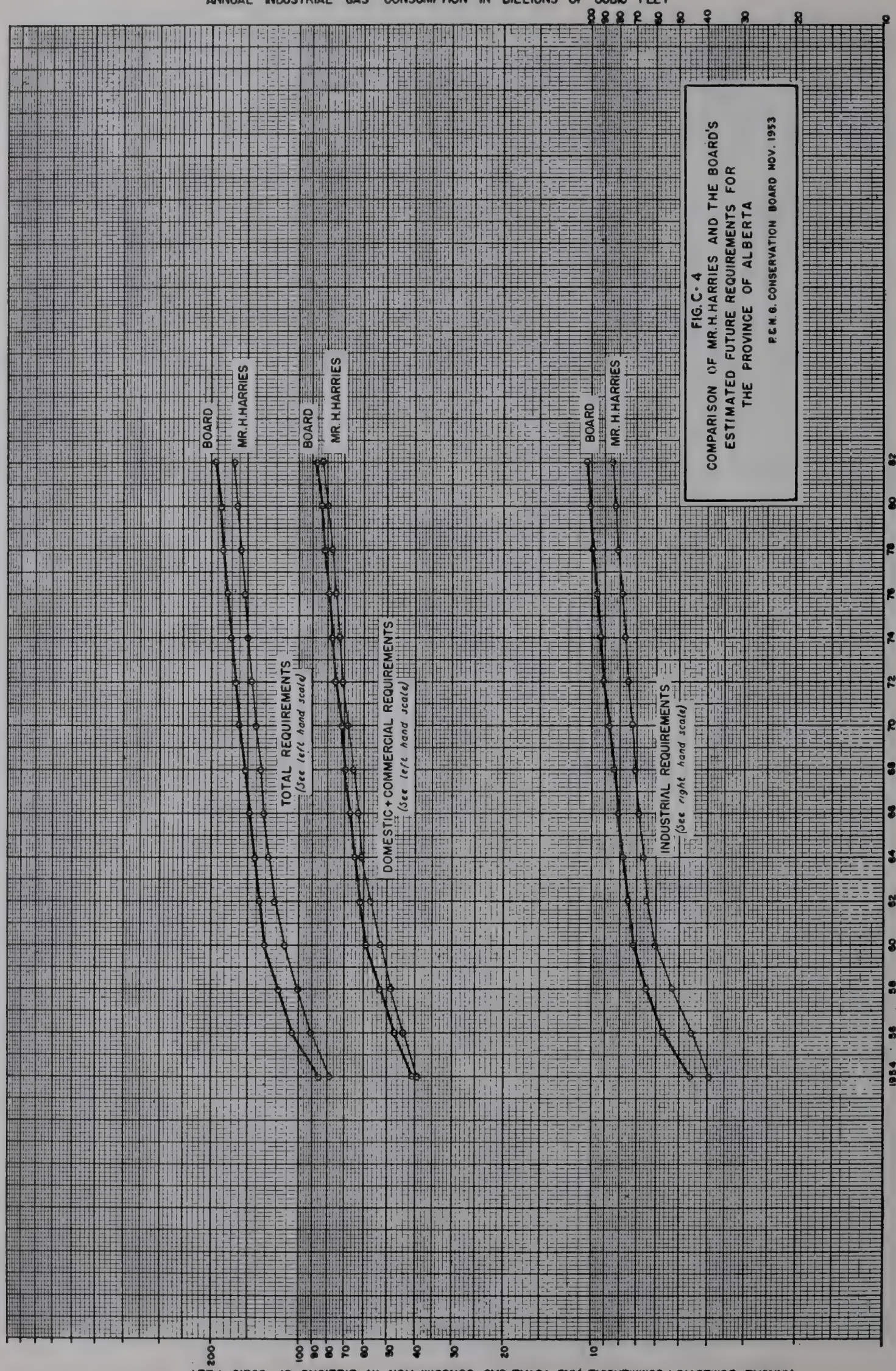


FIG-C-3
TREND IN THE USE OF NATURAL GAS
PROVINCE OF ALBERTA
Period 1930-1952 Based upon statistics and reliable estimates
Period 1953-1982 Projection
P. & N.G. CONSERVATION BOARD NOV. 1953


ANNUAL INDUSTRIAL GAS CONSUMPTION IN BILLIONS OF CUBIC FEET
FIG. C-4
COMPARISON OF MR. H. HARRIES AND THE BOARD'S ESTIMATED FUTURE REQUIREMENTS FOR THE PROVINCE OF ALBERTA
P.E.N.G. CONSERVATION BOARD NOV. 1953
BOARD
MR. H. HARRIES
TOTAL REQUIREMENTS
(See left hand scale)
DOMESTIC + COMMERCIAL REQUIREMENTS
(See left hand scale)
INDUSTRIAL REQUIREMENTS
(See right hand scale)
ANNUAL DOMESTIC + COMMERCIAL AND TOTAL GAS CONSUMPTION IN BILLIONS OF CUBIC FEET
YEAR
1954
56
58
60
62
64
66
68
70
72
74
76
78
80
82

APPENDIX D

IN THE MATTER OF MEETING THE PRESENT AND FUTURE REQUIREMENTS OF THE PROVINCE TOGETHER WITH ITS PRESENT EXPORT COMMITMENTS

During the hearings each of the applicants presented evidence and opinions as to how the requirements of the Province might be met from presently known reserves. As mentioned in Appendix C, Trans-Canada Pipe Lines Limited presented through Mr. H. Harries an independent study of the requirements of the Province for the period 1953 to 1982 inclusive. The results of Mr. Harries' study were not available to Mr. Trostel in time for his use. Mr. Trostel, therefore, based his plan for meeting the requirements of the Province upon the March 1952 findings of the Board concerning the requirements of the Province (extended to 1982) and upon his own estimates of reserves. Western Pipe Lines adopted the March 1952 estimates of the Board as to provincial requirements (extended to 1982) and Mr. Hawthorne based his plan for meeting requirements of the Province on these estimates and upon his own estimates of reserves. Canadian-Montana Pipeline Company also adopted the Board's previous provincial requirement figures and through Mr. Dodge indicated in summary form those fields which might be drawn upon to meet the deficiencies of the Northwestern Utilities, Limited area and the Canadian Western Natural Gas Company area referred to in the 1952 report of the Board. The Canadian Western Natural Gas Company Limited and the Northwestern Utilities, Limited, through their witness Mr. Brownie, outlined the plans of these companies for meeting their own future requirements. These plans, while not illustrated by deliverability schedules, indicated clearly the fields which in the opinion of the companies might best be employed to meet the future requirements of that part of the Province served by the companies.

The Board has reviewed all of these proposals in the light of its present findings as to the Established Reserves, the Trends in the Growth of Reserves, and the 1953-1982 Requirements of the Province. In this study the Board has in general followed the method employed in the March 1952 report.

The following tables, D-1 to D-12 are presented to show how the requirements of the Province might be met from the presently known reserves. These tables may be considered to be revisions of those of the March 1952 report and those of Messrs. Trostel and Hawthorne in the light of the Board's new estimate of provincial requirements and the Board's present findings as to reserves. The production schedules are believed to be realistic and practical on the basis of present knowledge. They should not, however, be interpreted too literally in view of the many contingencies involved.

The Area Tributary to The Northwestern Utilities, Limited System

In considering the manner in which the present and future requirements of the area tributary to the Northwestern Utilities, Limited system might be met, the Board adopted as a premise the concept that gas produced unavoidably with oil from nearby

oil fields would in effect have a prior claim to the nearby markets. This reflects the general policy of the Board and is consistent with the expressed views of the utility companies and of Trans-Canada Pipe Lines Limited and Western Pipe Lines.

Residue Gas From the Leduc-Woodbend Field

Table D-1 reflects the results of the Board's detailed review and analysis of the future availability of residue gas from the Leduc-Woodbend field. The figures of columns 2 to 14 inclusive, are all on a daily average basis. Column 2 of this tabulation presents the estimated production of gas from the D-2 and D-3 reservoirs within the field boundaries. This estimate like that of Mr. Trostel's was predicated on a forecast of oil production rates combined with gas-oil ratio trends. Column 2 reflects the substantial depletion of the D-2 solution and gas-cap gas and the D-3 solution gas reserves by 1967. The Board believes that starting in the early 1960's a certain amount of production of D-3 gas-cap gas will be virtually unavoidable. Estimates of production of such gas-cap gas up to the time of depletion of the oil reserves are presented in Column 3. Column 4 reflects the solution gas produced with oil from the Lower Cretaceous pool until the early 1960's. Thereafter, the figures reflect the production of Lower Cretaceous gas-cap gas and Viking gas at rates selected to facilitate processing plant operation. Column 5 indicates the total raw gas produced from the D-2 reservoir, all of the D-3 solution gas, that part of the D-3 gas-cap gas produced unavoidably with oil, all of the Lower Cretaceous solution gas, a substantial portion of the Lower Cretaceous gas-cap gas and most of the Viking gas. Column 6 presents figures indicating the portion of the gas produced shown in Column 5 which in the Board's opinion can economically be gathered. The entries in Column 6 have been calculated at ninety per cent of the entries in Column 5 except for the Lower Cretaceous gas-cap portion and the Viking gas which have been taken at one hundred per cent. The volumes of gas presently anticipated as being required for Golden Spike repressuring are entered in Column 7. These figures are based on the capacity of repressuring equipment initially being installed by Imperial Oil Limited. For the period 1956 to 1961 inclusive, the rates are increased because of the availability of more gathered gas than now thought to be capable of economic processing. Columns 8, 9 and 10 indicate the volumes of gas which, in the opinion of the Board, might reasonably and economically be handled by processing plants. The figures in Column 8 reflect deliveries to the existing gas conservation plant of Imperial Oil Limited. The figures in Columns 9 and 10 are for new plants expected to be built within the next few years. Column 11 presents the volumes of gas now considered to be uneconomic to process. These volumes result from the anticipated peak in gas production chiefly resulting from an unavoidable increase in the gas-oil ratio in the D-2 zone. The figures in Column 12 represent the total quantities of gas anticipated to be delivered to processing plants while those of Column 13 indicate the resulting residue gas available for disposal. The residue gas has been estimated at 81 per cent of the raw gas delivered to the plants. This figure is based upon the 1952-53 experience of the Imperial Oil gas conservation plant. Inasmuch as the market requirements of the area tributary to the Northwestern Utilities, Limited system are expressed in terms of gas having a heating value of approximately 1,000 B.T.U.'s per cubic foot, the residue gas figures of Column 13 are converted to the

equivalent volumes of 1,000 B.T.U. gas in Column 14. Column 15 presents the annual figures equivalent to those of Column 14. Column 16 expresses the estimates of the amount of residue gas on a 1,000 B.T.U. basis expected to be available at the time of market peaks—i.e. on the coldest winter day. These figures have been based on the assumption that each of the three processing plants could be operated in such a way that the ratio between the daily average output and the maximum output (which would be during the summer) would be about 95 per cent. It has also been assumed that the minimum deliveries from the plant in the winter months would be about 95 per cent of the average deliveries. These figures are believed to be realistic in view of the load levelling possibilities inherent in the Golden Spike repressuring scheme and in the use of Lower Cretaceous and Viking dry gas. Expressing the relationship between the figures of Column 14 and those of Column 16 as a market load factor; i.e. as the ratio of the average gas availability to the availability of gas during times of market peaks, gives the load factor figures of Column 17.

Residue Gas From Other Nearby Oil Fields

Table D-2 presents in summary form the results of similar analyses for other oil fields within the area tributary to the Northwestern Utilities, Limited System. All figures in this table are expressed in terms of 1,000 B.T.U. gas.

Columns 2, 3 and 4 give the projection for the Bonnie Glen and Wizard Lake fields. These figures are consistent with the Board estimates of the reserves of gas in these two fields and are higher than those used by Messrs. Hawthorne and Dodge who accepted earlier estimates of the Texaco Exploration Company. They are also higher than those employed by Messrs. Trostel and Davis. The figures reflect the substantial depletion of the oil reserves in the early 1970's and the continued production of the field on a wet gas basis.

Columns 5, 6 and 7 present the forecast for the Acheson field. The possibilities of load levelling through the production of some Lower Cretaceous gas in this field have been considered and are reflected in the lower market load factor entries of Column 7. The forecast contemplates the production of all the D-3 solution gas together with small amounts of D-2 and Lower Cretaceous gas. The construction of facilities for gathering and processing the Acheson gas is now under way.

Columns 8, 9 and 10 present the forecast of availability of gas of the Redwater field. While no facilities are currently under construction, the Board expects that conservation of gas in this field will be in full effect by 1955.

Columns 11, 12 and 13 refer to the availability of gas from the Joseph Lake and Armena-Camrose fields. Again no facilities are currently under construction but the Board anticipates that a conservation program will be in full effect by 1956 at the latest. The fact that the production quotas from these fields do not fluctuate greatly with the market demand gives rise to the lower market load factor figures shown in Column 13.

Columns 14, 15 and 16 give the projected availability of residue gas from the Campbell and Namao fields together with certain nearby wells. Gathering and pro-

cessing facilities in this area are anticipated by 1957 at the latest. The low market load factor of Column 16 results again from the expected minor variation of production quotas with fluctuations in market demand.

The impact of the unavoidably produced oil field gas referred to in Tables D-1 and D-2 upon the market of the area tributary to the Northwest Utilities, Limited system is considered in Table D-3. Columns 2, 3 and 4 present the estimated future requirements of the area as given in Table C-2. Columns 5, 6 and 7 present, on a 1,000 B.T.U. basis, the total available residue gas determined in Tables D-1 and D-2.

Dry Gas From Presently Connected and Nearby Fields

In addition to this residue gas available from the oil fields, dry gas is available from the presently connected Viking-Kinsella field and from certain smaller fields adjacent to the City of Edmonton which are also connected. It is contemplated that the Viking-Kinsella field and the other dry gas fields would produce at the load factor necessary to satisfy the remainder of the market. Columns 8, 9 and 10 show the estimated delivery capacity of the Viking-Kinsella field developed to a degree necessary to meet what is considered to be its share of the remaining market in the area. The delivery characteristics of the field are based upon basic data listed in Table D-4 which in turn are reflected by the deliverability-reserves relationship of Figure D-1.

The anticipated delivery from presently connected dry gas fields adjacent to Edmonton and other nearby fields not yet connected is indicated in Columns 11, 12 and 13 under the heading of "Edmonton Dry Gas Composite". This Composite includes the following fields or areas: Beaverhill Lake, Bon Accord - Lost Point Lake, Calahoo, Calmette, Fort Saskatchewan, Legal - Fairydell, Morinville, Picardville - Fairydell, St. Albert and Villeneuve. The delivery characteristics of the Composite are based upon the data listed in Table D-4 and reflected by the deliverability-reserves relationship of Figure D-2.

Table D-3 indicates that the Viking-Kinsella and Edmonton Dry Gas Composite fields are able to meet all the remaining requirements of the area tributary to the Northwestern Utilities, Limited system until 1972. At this time deferred gas is expected to be available from the Leduc D-3 gas cap and from the Viking and Lower Cretaceous zones of the Acheson and Excelsior fields. Under the heading of "Edmonton Deferred Gas Composite", Columns 14, 15 and 16 reflect the combined production of this deferred gas on a schedule designed to meet the remaining market requirements for the period 1972 to 1982. The fields have been treated as a composite with delivery characteristics based upon the data listed in Table D-4 and illustrated by the deliverability-reserve relationship of Figure D-3.

The Situation With Respect to the Northwestern Utilities, Limited, Area

It is to be noted that the total estimated requirements of the area tributary to the Northwestern Utilities, Limited system may be met from presently connected fields together with natural groupings of fields in close proximity to the City of Edmonton. No deficiencies exist over the thirty year period. Table D-3 indicates that of a total available solution gas reserve of 1,470 BCF some 69 per cent or 1,012 BCF would be

required and would find its logical market and be consumed in the area tributary to the system over the period January 1, 1953 to December 31, 1982. In the case of the Viking-Kinsella field with a remaining recoverable reserve of 629 BCF, this entire amount would be required and is assumed to be delivered to the system in the thirty year period. The Edmonton Dry Gas Composite has a total estimated recoverable reserve of 500 BCF. Table D-3 contemplates the delivery of some 468 BCF or approximately 94 per cent of this to the Edmonton area market in the thirty year period. On the other hand the Edmonton Deferred Gas Composite aggregating some 465 BCF is assumed to be only about 47 per cent used with the withdrawal of 219 BCF during the last ten years of the thirty year period. Actually, of the remaining reserve of 246 BCF of deferred oil field gas, all but about 25 BCF is necessary in order to insure deliverability in the year 1982 to meet the peak of 277 MMCFD shown in Column 15.

It is thus seen that the requirements of the Northwestern Utilities, Limited system and the tributary area may easily be met for the thirty year period from presently known reserves. Moreover, from presently known reserves there appears to be almost no choice as to which reserves would be used. Those that are included in Table D-3 are reserves all of which are very close to the City of Edmonton or already presently connected.

The Area Tributary to The Canadian Western Natural Gas Company Limited System

In its analysis of the various plans advocated for meeting the future requirements of the area tributary to the Canadian Western system, the Board employed an approach slightly different to that used for the Northwestern Utilities, Limited system. This arose from the fact that, except for Turner Valley, there is no similar problem in the provision of markets for unavoidably produced solution gas from oil fields. Accordingly, the procedure followed by the Board was similar to that employed in the March 1952 report.

Presently Connected Fields—Residual Requirements

Table D-5 in the present report is the counterpart of Table D-1 of the March 1952 report. Columns 2, 3 and 4 give the total requirements of the area as presented in Table C-2. Columns 5, 6 and 7 indicate the manner in which gas from the Turner Valley field is expected to be available. The delivery pattern here reflects the Board's revised estimate of reserves and takes into account the recent studies of Messrs. Trostel and Davis on the availability of both solution and gas cap gas. These figures differ somewhat from those in the corresponding columns of Table D-1 of the March 1952 report reflecting a refinement in estimate based on the above mentioned studies. Columns 8, 9 and 10 reflect the manner in which it is expected that the Jumping Pound field will supply gas to the Canadian Western market. The projection of the annual and peak day volumes for this field reflect the Board's present reserve estimate and the latest thoughts of the Shell Oil Company and the Canadian Western Natural Gas Company with respect to size and operating load factor of the processing plant.

Columns 11, 12 and 13 indicate the manner in which it is expected that the Foremost Field will supply gas to the Canadian Western system. The annual volumes indicated in Column 11 have been decreased to 0.2 BCF from the figure of 0.3 shown in Table D-1 of the 1952 report. This is more in line with the actual withdrawals from this field over the past two or three years. The peak day volumes have been based upon the delivery characteristics of the field. Column 14 indicates the manner in which it is expected that peak day gas will be available from the Bow Island field. The volumes have been projected in a manner such that the total deliveries from the Bow Island and Foremost fields will not exceed 55 MMCF per day. This figure corresponds with the maximum daily capacity of the transmission line from Bow Island and Foremost to Calgary as indicated in evidence, submitted by Mr. B. Snyder of the utilitiy companies. Columns 15, 16 and 17 reflect the residual requirements of the Canadian Western system after deliveries from the fields presently connected. The residual annual requirements start in 1957 at 1.6 BCF increasing to 50 BCF in 1982 and aggregating some 670 BCF by the end of 1982. Peak day deficiencies commence in the year 1956 at 5 MMCFD and increase to 288 MMCFD in the year 1982. The load factor of the residual requirements shown in Column 17 is substantially the same as that shown in the previous report increasing from approximately 25 per cent in 1957 to approximately 48 per cent in 1982. These residual requirements must be met from fields not presently connected to the Canadian Western Natural Gas system.

Other Possible Sources of Supply

The map, Figure A-1, which shows graphically both the location and the magnitude of the reserves of the Province is useful in the study of how these residual requirements best might be met. Also Table D-6 indicates the reserves, deliverability and distances to Calgary of all significant reserves within a radius of 200 miles. Columns 5 and 6 of this table indicate the established reserves per mile distance from Calgary and the maximum deliverability per mile distance from Calgary. These figures may be assumed to be rough indices of the relative desirability of the fields as sources of supply for the Calgary market. Column 7 presents remarks based upon Columns 5 and 6, as to the general suitability of the fields as sources of supply for the Calgary market. The lower part of the table presents similar figures and comments concerning logical geographical groupings of fields.

The Okotoks Field

This tabulation suggests the Okotoks field as a logical source of supply to the area tributary to the Canadian Western Natural Gas Company system and also indicates Pincher Creek, the Cessford Composite group of fields and the Homeglen Composite group of fields to be the only other satisfactory sources. The basic deliverability data of these fields and composites can be found in Table D-4. In its study of the proposals of others, the Board has assumed that the Okotoks field would be connected to the system and has analyzed the ability of each of Pincher Creek, the Cessford Composite and the Homeglen Composite to meet the remaining requirements.

Table D-7 presents the residual requirements of the area tributary to the Canadian Western Natural Gas Company system in Columns 2, 3 and 4 and the anticipated availability of gas from the Okotoks field in Columns 5, 6 and 7. The unsatisfied residual requirement is 603 BCF and 283 MMCFD in 1982.

Necessary Further Quantities

A preliminary idea of the quantity of reserves necessary to meet this unsatisfied residual requirement is useful in considering the proposals both of the applicants and of the Canadian Western Natural Gas Company. Figures D-4, D-5 and D-6 show the relationship between fully developed delivery capacity and remaining reserves of disposable gas for

(a) the Pincher Creek field;

(b) the Cessford Composite group of fields; and

(c) the Homeglen Composite group of fields.

These figures indicate that, on the basis of maximum field development, the quantities of disposable reserves required to meet the aggregate annual and the 1982 peak day unsatisfied residual requirements of the Canadian Western Natural Gas Company system would be those shown in the following table.

Table D-8

ESTABLISHED RESERVES REQUIRED, BCF

	For Annual Deficiency	For 1982 Peak Day	Required Total	Actual Established Reserves
Pincher Creek	603	1670	2273	2000
Cessford Composite	603	710	1313	1223
Homeglen Composite	603	665	1268	930

The Pincher Creek Field—Not a Solution

Pincher Creek, with an established reserve of 2000 BCF is seen to be incapable, by itself, of meeting the requirements. If it were possible, through storage or low load factor deliveries, to maintain the gas cap deliveries from Turner Valley at the 95 MMCFD level until 1982, the peak day requirement in 1982 would be reduced by 95—12=83 MMCFD (see Table D-5). Under these conditions the requirements from Pincher Creek would be 603 BCF for the annual deficiency plus 1150 BCF for the reduced 1982 peak day of 283 less 83, or 200 MMCFD. Thus a total reserve of 1753 BCF in Pincher Creek would, theoretically, satisfy the residual requirements of the Canadian Western system along with maintenance of gas cap deliveries from Turner Valley. Such a scheme is scarcely practical, however, since it contemplates deliveries from Pincher Creek at load factors in the range of 30 per cent to 60 per cent. The

load factors could be improved by simultaneous deliveries to an export market but these deliveries would have to be restricted to a total amount not to exceed 2000 less 1753 or 247 BCF to permit Pincher Creek still to meet the 200 MMCFD 1982 remaining peak day requirement. Such deliveries to export would be insufficient to bring the Pincher Creek load factor to a proper level for a sufficient number of years to permit economic operation of the field.

The Board is forced to the conclusion therefore, that the Pincher Creek field, even with the high peak day deliveries maintained from Turner Valley, is not by itself suited either with or without export to meet the deficiencies of the Canadian Western Natural Gas Company system.

The Cessford Composite Group of Fields—One Solution

Table D-8 indicates that some 1313 BCF would be required if the Cessford Composite by itself were to meet the annual and peak day deficiencies. The Board has estimated the established reserves of disposable gas from this group of fields at 1223 BCF, a figure close to the 1313 requirement. This indicates that the Cessford Composite would very nearly meet the requirements. A detailed analysis of this possibility is shown in Table D-7 where Columns 8, 9 and 10 indicate the deliveries expected from the Cessford Composite. The basic deliverability data of the fields included in the Cessford Composite are shown in Table D-4 and the deliverability-reserve relationship of the composite is shown in Figure D-5. Table D-7 shows that in the years 1981 and 1982 there would be both annual and peak day deficiencies due to the inability of the composite completely to meet the residual requirements of the system. These deficiencies are scarcely significant and are well within the margin of error in the forecast. It may, therefore, be concluded that the residual requirements of the area tributary to the Canadian Western Natural Gas Company Limited can readily be met from the Okotoks and the Cessford Composite fields. This is one possible solution to the problem based on presently known reserves.

The Homeglen Composite Group of Fields—A Second Solution

The only other distinct possibility is through the use of the Homeglen Composite. Table D-8 indicates that some 1268 BCF would be required to meet the Canadian Western Natural Gas Company's deficiencies if this gas were to come from the Homeglen Composite group of fields. The Board's estimate of the total reserve which may now be considered established in these fields is 930 BCF indicating that these fields by themselves could not meet the requirement. With gas cap deliveries maintained at Turner Valley to reduce the 1982 peak to near 200 MMCFD, the requirements from the Homeglen Composite would be reduced to 603 BCF plus 450 BCF or a total of 1053 BCF which is still in excess of the Board's estimate of the established reserves. The close proximity of the Homeglen Composite to the Westerose field and to the South Westerose, Pigeon Lake and Sylvan Lake areas suggests the use of deferred oil field gas from these areas to complement the reserves of the Homeglen Composite. Table D-9 is an analysis of this scheme. This table presents, along with

the projections for the other fields, a revised plan for producing the Turner Valley field in order to preserve its delivery capacity to the extent required. Columns 5 and 6 of the table indicate annual and peak day withdrawals from the Turner Valley Field which would result through the deferment of a portion of the gas cap production for peaking purposes in later years. Columns 8 to 14 inclusive, are identical with the corresponding columns in Table D-5. Columns 15 to 17, inclusive, show the manner in which it is expected that the Okotoks field will be able to deliver gas to the system when required. Columns 18 to 20, inclusive, show by individual fields the deliveries expected from the Homeglen Composite.

Columns 21, 22 and 23 indicate the method in which it is proposed that gas would be delivered from the Nevis field. An increase in plant capacity from an initial 5 million cubic feet per day residue gas in 1956 to a maximum of 57.6 MMCFD residue gas in the year 1962 is contemplated. Except for a few years a plant operating load factor of 70 per cent can be expected. In the years 1957 to 1959 inclusive, small amounts of Lower Cretaceous gas are included in the peak day deliveries from this field.

Columns 24, 25 and 26 indicate the manner in which it is contemplated that the Homeglen-Rimbey field will supply gas to the system. Deliveries are shown to commence in the year 1957 inasmuch as they are not required for the Canadian Western Natural Gas Company system prior to that date. It is assumed that gas produced up to that time could be conserved by re-injection into the gas cap. It is contemplated that the field will be produced primarily as an oil field until the year 1966 and that the market load factor will be 111 per cent until that time. In 1967 the field becomes primarily a wet gas field and it is assumed that the market load factor will be in the neighbourhood of 70 per cent. The plant capacity is increased as required until a maximum size of 96 MMCFD marketable gas is reached in 1972.

The residual requirements of the Canadian Western Natural Gas Company system can be met by the Homeglen Composite until the year 1974. At this time, deferred oil field gas from the Westerose field and from the Pigeon Lake, South Westerose and Sylvan Lake areas is available. Columns 27, 28 and 29 indicate how gas from these areas may be used to meet the remaining requirements. The basic deliverability data for these fields are included in Table D-4 and the deliverability-reserve relationship is shown in Figure D-7.

From Table D-9 the Board concludes that with the maintenance of high deliveries from the Turner Valley gas cap, the residual requirements of the area tributary to the Canadian Western Natural Gas Company Limited system may be met from the Okotoks and Homeglen Composite fields together with deferred oil field gas from the Westerose area. This is another possible solution to the problem based on presently known reserves.

The Better Solution for the Canadian Western Natural Gas Company Area—

Use of the Homeglen Composite

In its consideration of the two alternates to the meeting of the residual requirements of the Canadian Western area, the Board has had in mind

(a) the fact that gas from the Pincher Creek field is not suitable or needed to meet the 30 year requirements of the Province thus making possible its eastward movement;

(b) the testimony of geologists and engineers together with the record of the past year and a half indicating the excellent prospects for further gas discoveries west of the Calgary-Edmonton line;

(c) the testimony of Messrs. Davis and Brownie to the effect that the utility companies believe the Homeglen-Rimbey group of fields to be the best source of additional supply for the Canadian Western system; and

(d) the testimony of Mr. Brownie to the effect that the towns along the Red Deer-Calgary line could economically be served from a main gathering line extending from Homeglen to Calgary.

The Board can see no point to moving gas westward from the Cessford Composite to Calgary resulting in the development of a surplus in the Homeglen area which presumably would then be moved southeasterly to join Pincher Creek gas flowing east. This clearly would involve wasteful movement of gas as compared with the southward movement of the Homeglen Composite gas to Calgary and the eastward movement of Pincher Creek, Cessford Composite, and other surplus gas. Moreover, there are definite advantages to the Province in the routing of pipeline facilities necessary to meet Canadian Western Natural Gas Company's requirements in a manner which would facilitate connection to reserves as yet undiscovered for the possible use either of Canadian Western Natural Gas Company Limited or Northwestern Utilities, Limited. The line from Calgary to Homeglen, skirting the eastern edge of exceptionally favorable potential gas land, and extending two-thirds of the way to Edmonton, follows such a route. While gas service to the towns along the Red Deer-Calgary line would eventually come even without the Calgary-Homeglen connection, the chances are that these communities could obtain gas service earlier and at better rates from such a pipeline. A gathering line from Calgary to the Cessford area on the other hand, would neither pass through as favorable prospective gas lands nor permit service to as many communities.

For these reasons the Board believes, that from presently known reserves, the best manner of meeting the residual requirements of the area tributary to the Canadian Western Natural Gas Company system is the second alternate, namely, the scheme advocated by the utility companies—the use of the Homeglen Composite.

Peace River Area

The Board has reviewed the ability of the reserves of the Peace River Area of the Province, as presently estimated, to meet both the requirements of that area of the Province and the present export commitments from it.

Table D-10 shows the manner in which it is contemplated that these requirements could be met from the presently known reserves. Columns 2, 3 and 4 show the projected requirements of the Alberta communities in the Peace River Area; Columns 5, 6 and 7 indicate the present export commitments to Dawson Creek; while Columns 8, 9 and 10 indicate the gas presently committed to the Westcoast Transmission Company Limited for export to the Pacific Northwest. These projections are those discussed in detail in Appendix C and Table C-2. The requirements as shown in Columns 2 to 10 inclusive, have been combined and the total of the Peace River requirements within the Province and the present export commitments from the Peace River area of the Province appears in Columns 11 to 13.

In considering the manner in which these requirements and present commitments best could be met, the Board has found it convenient to group into a single composite all of those fields within the Peace River area of the Province which presently appear to the Board to be capable of economic use. This "Peace River Composite" includes the following fields: Belloy, Dunvegan, Eaglesham, Gordondale, Hamelin Creek, Pouce Coupe, Rycroft, Tangent and Whitelaw. The basic deliverability data for these fields or areas are included in Table D-4 and the deliverability-reserve relationship is shown in Figure D-8.

The figures in Columns 14, 15 and 16 of Table D-10 reflect a delivery projection from the Peace River Composite designed fully to meet the requirements listed in Columns 11, 12 and 13 and, in addition, to indicate through Columns 17, 18 and 19 any excess gas. Thus until the end of 1959, the entries in Columns 14, 15 and 16 are identical with those in Columns 11, 12 and 13. From 1960 to 1970 inclusive, the entries in Columns 14 and 15 exceed those in Columns 11 and 12 by the amounts shown in Columns 17 and 18. These latter amounts indicate the excess gas over and above that necessary to meet the requirements of Columns 11 and 12 and have been calculated so as to leave the Peace River Composite fully capable of meeting the requirements of the Peace River Area of the Province and the present Dawson Creek export commitments in the year 1982. The total of Column 17 indicates a total excess gas, over and above present commitments, of some 217 BCF. If this excess gas were committed to export some 547 BCF or 94 per cent of the presently estimated disposable reserve of the Peace River Composite would be produced over the thirty year period.

Medicine Hat Area

The Board has investigated the ability of the Medicine Hat field (including the Many Islands area) to meet the present and future requirements of the Medicine Hat area of the Province as presented in Table C-2 of Appendix C. Basic deliverability

data for the field are presented in Table D-4 and the reserve-deliverability relationship is shown in Figure D-9.

The curve CB of Figure D-9 reflects the increasing peak day requirements of Medicine Hat-Redcliff (Column 12 of Table C2) with the continued withdrawal of reserves to meet the annual requirements (Column 11 of Table C-2). This curve terminates at the 1982 peak day level of 64 MMCF and after the withdrawal of 305 BCF. It is noted that this peak day requirement is only some 60 per cent of the maximum delivery capacity which the entire field would have after the withdrawal of 305 BCF. Accordingly, the Board has considered it proper, in effect, to divide the field into that portion needed for the Medicine Hat-Redcliffe requirements and the remaining portion. This division of the reserves has been proportioned upon the deliverability-reserve relationship of the entire field. Line AB reflects the maximum deliverability-reserve relationship of that portion of the field required for the communities and indicates a remaining disposable reserve, not required for the Medicine Hat Area of some 230 BCF. The total reserves needed for the protection of the Medicine Hat area are, therefore, 855 BCF less 230 BCF, or 625 BCF.

Thus the Medicine Hat field is seen not only to be fully capable of meeting the present and future requirements of the nearby Alberta communities but also to contain some 230 BCF of gas in excess. This excess gas may most reasonably be considered to be that producible from the eastern and northern portions of the field most remote from the communities.

Pakowki Lake Area

Under the provisions of The Gas Export Act the Province is committed to the export, to the Montana Power Company, of a further some 32.3 BCF (January 1, 1953 to April 6, 1956) from the Pendant d'Oreille, Smith Coulee and Black Butte fields of the Pakowki Lake area. The Board has investigated the ability of these and other nearby fields to meet these commitments and has determined the amount of excess gas available in the area.

The illustrative deliverability schedule Table D-11 presents the results of these studies. For convenience the Pendant d'Oreille, Smith Coulee and Black Butte fields together with the isolated Comrey well, have been treated as a group referred to as the Pakowki Composite. The basic deliverability data for these fields and the composite appear in Table D-4 and the deliverability-reserve relationship is presented in Figure D-10.

In Table D-11, Columns 2, 3 and 4 indicate the present (Gas Export Act) commitments to the Montana Power Company. Columns 5, 6 and 7 show that in the year 1953 the Pakowki Composite can easily deliver the required quantities of gas. Thereafter, excess gas could easily be produced from the Pakowki Composite to the totals shown in Columns 5 and 6. Moreover, both the Manyberries and Etzikom fields are considered by the Board to be within the same logical geographical grouping as the Pakowki Composite. Accordingly, these fields have been included in the study presented through Table D-11. Basic deliverability data for the Manyberries and

Etzikom fields appear in Table D-4. Columns 8 to 13 inclusive, indicate a reasonable manner in which these fields could be produced. The total gas, in excess of the present Montana commitments, producible over the thirty year period from the Pakowki Composite, Manyberries and Etzikom fields, is listed in Columns 14, 15 and 16. Its aggregate amount is 321 BCF. On the production schedule illustrated by Table D-11 the Pakowki Composite and the Manyberries fields would be substantially depleted by about 1975 and the schedule was, therefore, not carried beyond this date.

Remainder of the Province

Table C-2 shows that the total requirements of the local systems now in operation or likely to be installed within the next thirty years are estimated at 356 BCF with a 1982 peak day load of 116 MMCFD. Provided for in these requirements are all towns and communities having a present population more than 300 and not now served by either large utility, but excluding Medicine Hat-Redcliffe and the Peace River areas.

Distribution of the Requirements

It is considered that a portion of these local requirements will be met by individual systems obtaining gas from small fields adjacent to the markets. The balance of the requirements will be met from larger fields producing to an export market and from main transmission lines. On the basis of the location of presently known small reserves and the proposed routing of pipelines, the Board estimates that about two-thirds of the local requirements will be met directly from small reserves and about one-third will be supplied through major transmission systems. This means that the small reserves should be capable of supplying some 240 BCF and meeting a 1982 peak day requirement of 80 MMCF. The transmission systems, on the other hand, would be called upon for the supply of 120 BCF and to meet a 1982 peak day requirement of 40 MMCF.

Service from Small Fields

From the locations of the communities to be served with natural gas in the next thirty years and the locations of the presently known reserves, the fields shown in Table D-12 have been considered by the Board as likely sources to deliver gas to that portion of the local market (two-thirds share) which will not be served by major transmission systems. Based on the deliverability characteristics of Alberta plains fields, the reserves necessary to meet this portion of the thirty year requirements plus the peak day in 1982, would be 240 BCF plus 120 BCF, or 360 BCF. From Table D-12 it may be seen that the estimated total available gas from the presently known, suitably located, reserves is 285 BCF. In several cases, however, the reserves adjacent to communities greatly exceed the market available to them. It is therefore, necessary to discount the 285 BCF figure to obtain the reserve which can be considered as effective protection. The Board estimates this effective reserve as 150-200 BCF—compared with the 360 BCF needed for the thirty years. This means that approximately one-half of that portion of the local requirements to be supplied by small or isolated fields can be met from suitable presently known reserves.

Most of these small communities can obtain economical gas service only if gas is discovered in close proximity to them. Without such discoveries there is, in the economic sense, no real requirement to be met. Moreover, in the light of the conclusions reached in Appendix B dealing with trends, it is apparent that the remaining local requirement (aggregating 150-200 BCF) is minute compared with expected new discoveries even over the next ten years. Accordingly the Board takes the position that, considering the requirements in a realistic economic sense, and bearing in mind the discovery trend, the small reserves can meet their estimated two-thirds share of the local requirements of the Province.

Service from Transmission Lines

From the overall deliverability characteristics of fields which will supply the major transmission lines, it is estimated that the reserves necessary to meet that portion of the local requirements to be supplied by the lines will be 120 BCF plus 80 BCF or 200 BCF. The Board sees no difficulty whatsoever in meeting this requirement from the existing and the future transmission lines. Provision for this requirement is made in the deliverability schedules presented in Appendix F.

RECAPITULATION

In summary the Board finds that the present and future requirements of the Province (January 1, 1953 to December 31, 1982), together with its present export commitments may easily be met from presently established reserves of disposable gas.

Northwestern Area

The requirements of the area tributary to the Northwestern Utilities, Limited system may be met from the following fields and reserves:

Field or Composite	Total Reserves Available For Disposition BCF	Thirty Year Withdrawal BCF	Per Cent Depleted	Total Reserves Committed to Requirements BCF
Leduc-Woodbend	448.9	433.1	96.5	448.9
Bonnie Glen & Wizard Lake	830.1	551.3	66.4	830.1
Acheson	36.5	35.9	98.4	36.5
Redwater	62.5	61.9	99.0	62.5
Joseph Lake - Armena-Camrose	65.1	65.1	100.0	65.1
Campbell-Namao	40.0	40.0	100.0	40.0
Viking - Kinsella	629.0	629.0	100.0	629.0
Edmonton Dry Gas Composite	503.7	468.0	93.0	503.7
Edmonton Deferred Gas Composite	464.7	219.1	46.7	439.0
Total Northwestern	3,080.5	2,503.4	81.3	3,054.8

Canadian Western Area

The requirements of the tributary to the Canadian Western Natural Gas Company Limited may be met from the following fields and reserves:

Field or Composite	Total Reserves Available For Disposition BCF	Thirty Year Withdrawal BCF	Per Cent Depleted	Total Reserves Committed to Requirements BCF
Turner Valley	370	352.6	95.0	370
Jumping Pound	375	332.4	86.0	375
Foremost	21	6.0	29.0	21
Bow Island	16	----	---	16
Okotoks	100	64.7	64.7	100
Homeglen Composite	930	660.4	71.0	930
Deferred Westerose Composite	195	34.5	17.7	195
Total Canadian Western	2,007	1,450.6	72.3	2,007

The Balance of the Province

The reserves required to meet the requirements of the balance of the Province plus the presently committed export volumes are shown hereunder with their associated fields:

Field or Composite	Total Reserves Available For Disposition BCF	Thirty Year Withdrawal BCF	Per Cent Depleted	Total Reserves Committed to Requirements BCF
Medicine Hat	855.0	305.0	35.7	623.0
Peace River Composite	580.6	329.9	56.8	363.5
Pakowki Composite	241.0	32.3	15.3	32.3
Remainder of Province:				
From Small Fields	200.0	----	---	360.0
From Transmission Lines				200.0
Total Balance of Province	1,876.6	667.2	35.6	1,578.8
GRAND TOTAL ENTIRE PROVINCE	6,964.1	4,621.2	66.4	6,640.6
				say 6.7 TCF

Thus the Board finds that a total of some 6.7 TCF of gas is required to meet its estimates of the present and future requirements (1953-1982) and the present export commitments of the Province. This figure has been developed with the aid of illustrative deliverability schedules believed realistic. The Board must emphasize, however, that future development could and probably will indicate other and better ways of meeting these requirements. While such development would not significantly alter the total quantity of gas which must be held in reserve their possibility dictates the need for flexibility in the development and utilization of the reserves of the Province.

APPENDIX D

Table D-I

The Petroleum and Natural Gas Conservation Board

FORECAST OF AVAILABILITY OF RESIDUE GAS FROM THE LEDUC WOODBEND FIELD

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Year	D2 Gas Plus D3 Sol'n. Gas Prod'n. MMCFD Ave.	Unavoidable D3 Gas Cap Prod'n. MMCF. Ave.	Lower Cret. and Viking Gas Prod'n. MMCFD. Ave.	Total Raw Gas Prod'n. MMCFD. Ave.	Total Gas Gathered* MMCFD. Ave.	To Golden Spike for Repressuring MMCFD Ave.	To Leduc Cons. Plant MMCFD. Ave.	To Plant No. 2 MMCFD Ave.	To Plant No. 3 MMCFD. Ave.	Economics of Processing Doubtful MMCFD Ave.	Total Raw Gas Processed MMCFD Ave.	Total Residue Gas @ 81% MMCFD Ave.	Total Residue Gas on 1000 BTU Basis* MMCFD. Ave.	Total Residue Gas B.C.F.	Peak Market Day MMCFD	Load Factor Per Cent
1953	40.6		0.4	41.0	36.9	10	24.0			2.9	24.0	19.4	22.5	8.2	21.4	105
1954	43.8		0.4	44.2	39.8	10	24.0			5.8	24.0	19.4	22.5	8.2	21.4	105
1955	49.6		0.5	50.1	45.1	10	24.0	4.7		6.4	28.7	23.2	26.9	9.8	25.6	105
1956	64.3		0.6	64.9	58.4	10	24.0	12.0	12.4	0	48.4	39.2	45.5	16.6	43.3	105
1957	85.0		0.8	85.8	77.2	15	24.0	12.0	21.0	5.2	57.0	46.1	53.5	19.5	50.9	105
1958	92.2		0.9	93.1	83.8	15	24.0	12.0	21.0	11.8	57.0	46.1	53.5	19.5	50.9	105
1959	94.8		0.9	95.7	86.1	15	24.0	12.0	21.0	14.1	57.0	46.1	53.5	19.5	50.9	105
1960	93.7		0.9	94.6	85.1	15	24.0	12.0	21.0	13.1	57.0	46.1	53.5	19.5	50.9	105
1961	79.3		1.0	80.3	72.3	15	24.0	12.0	21.0	0.3	57.0	46.1	53.5	19.5	50.9	105
1962	69.4		2.7	72.1	65.1**	10	22.1	12.0	21.0	0	55.1	44.6	51.7	18.9	49.2	105
1963	59.1	1.0	9.9	70.0	64.0	10	21.0	12.0	21.0		54.0	43.7	50.7	18.5	48.3	105
1964	49.7	2.5	17.0	69.2	64.0	10	21.0	12.0	21.0		54.0	43.7	50.7	18.5	48.3	105
1965	41.4	4.5	22.7	68.6	64.0	10	21.0	12.0	21.0		54.0	43.7	50.7	18.5	48.3	105
1966	21.1	10.8	35.3	67.2	64.0	10	21.0	12.0	21.0		54.0	43.7	50.7	18.5	48.3	105
1967	9.3	20.9	36.8	67.0	64.0	10	21.0	12.0			54.0	43.7	50.7	18.5	48.3	105
1968			36.5	36.5	36.5	10	14.5	12.0			26.5	21.5	24.9	9.1	31.1	80
1969			31.0	31.0	31.0	10	12.0	9.0			21.0	17.0	19.7	7.2	24.6	80
1970			26.5	26.5	26.5	10	9.0	7.5			16.5	13.4	15.5	5.7	19.4	80
1971			23.1	23.1	23.1	10	7.1	6.0			13.1	10.6	12.3	4.5	15.4	80
1972			20.0	20.0	20.0	10	5.0	5.0			10.0	8.1	9.4	3.4	11.8	80
1973			16.4	16.4	16.4	10	6.4				6.4	5.2	6.0	2.2	7.5	80
1974			14.2	14.2	14.2	10	4.2				4.2	3.4	3.9	1.4	4.9	80
1975			12.0	12.0	12.0	10	2.0				2.0	1.6	1.9	0.7	2.4	80
1976			10.6	10.6	10.6	10	0.6				0.6	0.5	0.6	0.2	0.7	80
1977			10.0	10.0	10.0	10										
1978			10.0	10.0	10.0	10										
1979			10.0	10.0	10.0	10										
1980			10.0	10.0	10.0	10										
1981			8.7	8.7	8.7	8.7										
1982			7.4	7.4	7.4	7.4										
Total B.C.F.	325.8	14.5	153.3	493.6	459.2	132.9	147.2	68.6	88.6	21.9	304.5	246.6	286.1	286.1		
														448.9		
Established Reserves Available for Disposition														63.7		
Per Cent Withdrawn						28.2				4.6						

*90% of Total Production

**Includes 100% of Lower Cretaceous Production

*Factor = 1.16

Table D-2

The Petroleum and Natural Gas Conservation Board

FORECAST OF RESIDUE GAS AVAILABLE FROM OTHER FIELDS ADJACENT TO THE EDMONTON AREA (on 1,000 B.T.U./cu. ft. basis*)

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
	BONNIE GLEN AND WIZARD LAKE FIELDS			ACHESON FIELD			REDWATER FIELD			JOSEPH LAKE AND ARMENA CAMROSE FIELDS			CAMPBELL AND NAMAO FIELDS		
Year	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent
1953															
1954				0.6	4.4	105									
1955	8.9	20.6	117.6	1.8	4.7	105	3.1	7.3	117.6						
1956	12.5	29.2	117.6	1.9	5.0	105	3.1	7.3	117.6	3.4	8.9	105			
1957	15.3	35.5	117.6	1.9	5.0	105	3.1	7.3	117.6	3.9	10.2	105	1.0	2.6	105
1958	16.0	37.2	117.6	1.8	4.7	105	3.0	7.0	117.6	4.3	11.2	105	1.2	3.1	105
1959	16.0	37.2	117.6	1.8	4.7	105	2.9	6.7	117.6	4.5	11.8	105	1.3	3.4	105
1960	16.0	37.2	117.6	1.8	4.7	105	2.9	6.7	117.6	4.6	12.0	105	1.4	3.6	105
1961	16.0	37.2	117.6	1.9	5.0	105	2.8	6.4	117.6	4.7	12.3	105	1.4	3.6	105
1962	14.7	34.4	117.6	1.9	5.0	105	2.7	6.1	117.6	4.6	12.0	105	1.4	3.6	105
1963	14.7	34.4	117.6	2.0	5.2	105	2.5	8.8	117.6	4.6	12.0	105	1.6	4.2	105
1964	14.5	33.8	117.6	2.0	5.2	105	2.4	5.5	117.6	4.3	11.2	105	1.8	4.7	105
1965	13.5	31.5	117.6	2.0	5.2	105	2.3	5.2	117.6	4.2	11.0	105	1.8	4.7	105
1966	13.4	31.2	117.6	1.8	4.7	105	2.3	5.2	117.6	4.0	10.5	105	1.8	4.7	105
1967	13.9	32.4	117.6	1.7	4.4	105	2.3	5.2	117.6	3.7	9.7	105	1.8	4.7	105
1968	14.5	33.8	117.6	1.8	4.7	105	2.1	4.9	117.6	3.0	7.8	105	1.8	4.7	105
1969	15.0	34.9	117.6	1.9	5.0	105	2.1	4.9	117.6	2.5	6.5	105	1.8	4.7	105
1970	15.0	34.9	117.6	1.9	5.0	105	2.1	4.9	117.6	2.0	5.2	105	1.8	4.7	105
1971	15.0	34.9	117.6	1.9	5.0	105	2.1	4.9	117.6				1.8	4.7	105
1972	15.0	34.9	117.6	1.9	5.0	105	2.1	4.9	117.6				1.8	4.7	105
1973	15.0	34.9	117.6				2.0	4.7	117.6				1.8	4.7	105
1974	15.0	34.9	117.6				2.0	4.7	117.6				1.8	4.7	105
1975	16.0	55.0	80.0				1.9	4.4	117.6				1.8	4.7	105
1976	23.4	80.0	80.0				1.7	4.1	117.6				1.8	4.7	105
1977	35.0	120.0	80.0				1.5	3.5	117.6				1.8	4.7	105
1978	35.0	120.0	80.0				1.3	2.9	117.6				1.8	4.7	105
1979	35.0	120.0	80.0										1.5	3.9	105
1980	35.0	120.0	80.0												
1981	35.0	120.0	80.0												
1982	35.0	120.0	80.0												
Total	539.3			34.3			56.3			58.3			37.8		
Waste prior to plant comp.	12.0			1.6			5.6			6.8			2.2		
Estab. Res. Avail. for Disp.	830.1			36.5			62.5			100.0			40.0		
% Withdrawn	66.4			98.4			99.0			65.1			100.0		
*B.T.U. Conversion Factor	1.23				1.20			1.25			1.085			1.00	

Table D-3

The Petroleum and Natural Gas Conservation Board

ILLUSTRATIVE DELIVERABILITY SCHEDULE FOR THE AREA TRIBUTARY TO THE NORTHWESTERN UTILITIES LIMITED SYSTEM

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
	TOTAL REQUIREMENTS			TOTAL OIL FIELD GAS			VIKING-KINSELLA			EDMONTON DRY GAS COMPOSITE			EDMONTON DEFERRED GAS COMPOSITE		
Year	Annual B.C.F.	Peak MMCFD	Load Factor Per Cent	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent	Annual B.C.F.	Peak MMCFD.	Local Factor Per Cent
1953	31.0	189	45	8.2	21.4	105.0	12.7	93.2	37.4	10.1	74.4	37.4			
1954	43.6	249	48	8.8	25.8	105.0	19.3	124.0	42.6	15.5	99.2	42.6			
1955	50.0	285	48	23.6	58.2	111.1	14.7	126.1	31.9	11.7	100.7	31.9			
1956	55.6	311	49	37.5	93.7	109.7	10.1	120.8	22.9	8.0	96.5	22.9			
1957	61.6	335	50	44.7	111.5	109.9	9.4	124.3	20.7	7.5	99.2	20.7			
1958	64.0	351	50	45.8	114.1	110.0	10.1	131.7	21.0	8.1	105.2	21.0			
1959	67.0	367	50	46.0	114.7	110.0	11.7	140.3	22.8	9.3	112.0	22.8			
1960	70.2	385	50	46.2	115.1	110.0	13.3	150.0	24.3	10.7	119.9	24.3			
1961	71.4	391	50	46.3	115.4	110.0	14.0	153.2	25.0	11.1	122.4	25.0			
1962	72.7	398	50	44.2	110.3	110.0	15.9	160.0	27.2	12.6	127.7	27.2			
1963	74.2	407	50	43.9	109.9	109.4	16.8	165.2	27.9	13.5	131.9	27.9			
1964	75.5	414	50	43.5	108.7	109.9	17.8	169.7	28.8	14.2	135.6	28.8			
1965	76.8	421	50	42.3	105.9	109.5	19.2	175.2	30.0	15.3	139.9	30.0			
1966	78.3	429	50	41.8	104.6	109.6	20.3	180.4	30.8	16.2	144.0	30.8			
1967	79.8	437	50	41.9	104.7	109.7	21.1	184.8	31.3	16.8	147.5	31.3			
1968	81.2	445	50	32.3	87.0	101.8	27.2	199.0	37.4	21.7	159.0	37.4			
1969	82.8	454	50	30.5	80.6	103.7	29.1	207.6	39.4	23.2	165.8	39.4			
1970	84.2	461	50	28.5	74.1	105.3	31.0	213.0	39.9	24.7	173.9	38.9			
1971	85.4	468	50	25.3	64.9	106.9	31.0	200.0	42.5	29.1	203.1	39.3			
1972	86.6	475	50	24.2	61.3	108.2	30.5	183.0	45.6	30.0	210.0	39.2	1.9	20.7	25.1
1973	87.8	481	50	21.0	51.8	111.1	30.0	175.0	46.0	30.0	183.0	46.9	6.8	71.2	26.2
1974	89.1	488	50	20.2	49.2	112.5	29.0	162.0	49.0	27.0	159.0	46.5	12.9	117.8	32.8
1975	90.4	495	50	20.4	66.5	84.1	28.0	151.0	50.8	21.4	140.0	42.0	20.6	137.5	41.1
1976	91.6	502	50	27.1	89.5	83.0	27.0	140.0	52.9	16.9	125.0	37.0	20.6	147.5	38.3
1977	92.9	509	50	38.3	128.2	81.9	26.0	128.0	55.7	12.7	112.5	31.0	15.9	140.3	31.0
1978	94.1	516	50	38.1	127.6	81.8	25.0	118.0	58.0	11.6	103.0	31.0	19.4	167.4	31.8
1979	95.6	524	50	36.5	123.9	80.7	24.0	108.0	60.9	10.9	93.4	32.0	24.2	198.7	33.4
1980	96.9	531	50	35.0	120.0	80.0	23.0	99.0	63.7	10.3	83.0	34.0	28.6	229.0	34.2
1981	98.2	538	50	35.0	120.0	80.0	22.0	89.0	67.8	9.3	74.9	34.0	31.9	254.1	34.4
1982	99.7	546	50	35.0	120.0	80.0	19.8	81.0	67.0	8.6	67.4	35.0	36.3	277.6	35.9
Total	2,328.2			1,012.1			629.0			468.0			219.1		
Waste prior to plant completion				28.2											
Established Reserves Available for Disp.				1,469.5			629.0			503.7			464.7		
Percentage Withdrawn				70.8			100.0			93.0			47.1		

Table D-4
The Petroleum and Natural Gas Conservation Board
BASIC DELIVERABILITY DATA FOR FIELDS OF TABLES D-3, D-5, D-7, and D-9

1	2	3	4	5
Name of Field	Zone	Present No. of Wells	Estimated No. of Wells (Field Fully Developed)	Absolute Open Flow Per Well Disposable Gas Millions of Cubic Feet Per Day
Viking Kinsella	Viking	100	150	9.2
Edmonton Dry Gas Composite				
Beaverhill Lake	Viking	4	15	11.9
Bon Accord-Lost Point Lake	Viking	9	15	8.2
Calahoo	Basal Blairmore	1	1	7.6
Calmette	Viking	1	1	5.6
Fort Saskatchewan	Viking	17	30	25.8
Legal Fairydell	Basal Blairmore	2	10	6.6
Morinville	Basil Quartz	15	25	11.3
Picardville Fairydell	Viking	9	45	6.6
St. Albert	Basal Quartz and Ostracod	4	7	28.5
Villeneuve	Viking	1	3	5.7
Total		63	152	12.8
Edmonton Deferred Gas Composite				
Acheson	Viking and Lower Cretaceous	0	10	5.5
Excelsior	Viking and Lower Cretaceous	2	6	9.0
Leduc	Leduc Gas Cap	0	70	25.5
Total		2	86	22.0
Jumping Pound	Rundle	7	11	26.1
Foremost	Bow Island	6	6	12.4
Pincher Creek	Rundle	9	24	55.5
Okotoks	Wabamun	6	12	4.8
Cessford Composite				
Unassociated				
Cessford, Sunnynook, Bullpound	Viking	2	18	3.9
Cessford, Steveville Sunnynook	Basal Colorado (Unassoc.)	5	65	4.8
Cessford, Sunnynook	Sunburst (Unassoc.)	2	9	6.8
Countess	Bow Island	3	7	2.8
Duchess	Basal Colorado	2	3	8.1
Patricia	Sunburst	1	1	3.8
Princess, Steveville	Basal Colorado	5	23	7.6
	Sunburst	6	9	7.6
Denhart	Rundle	3	4	5.7
	Jefferson	1	6	2.1
Total		30	145	5.3
Associated				
Cessford Steveville Sunnynook	Basal Colorado (Assoc.)	9	90	7.0
Cessford Sunnynook	Sunburst Assoc.	7	50	7.4
Total		16	140	7.1

Table D-4 (Continued)

1	2	3	4	5
Name of Field	Zone	Present No. of Wells	Estimated No. of Wells (Field Fully Developed)	Absolute Open Flow Per Well Disposable Gas Millions of Cubic Feet Per Day
Homeglen Composite				
Olds	Wabamun	3	5	4.4
Nevis	Lower Cretaceous	1	3	8.5
	Devonian	5	22	14.4
Homeglen Rimbey	Leduc	0	50	16.0
Deferred Westerose Composite				
Pigeon Lake	Leduc	1	1	25.5
Sylvan Lake	Blairmore and Mississippian	1	2	9.2
Westerose	Leduc	0	16	18.0
Westerose South	Leduc	1	1	24.0
Total		3	20	17.8
Medicine Hat Composite	Medicine Hat S.S.	90	200	2.7
	Bow Island	0	4	6.7
	Ellis	2	4	10.5
Total		92	208	2.9
Pakowki Composite				
Black Butte	Bow Island	0	2	1.9
Pinhorn	Ribbon	1	3	9.5
	Ellis	2	3	9.5
	Rundle	0	2	2.7
Comrey	Bow Island	1	1	4.3
Pendant D'Oreille	Bow Island	14	36	16.9
Smith Coulee	Bow Island	3	7	1.7
Total		21	54	12.8
Etzikom	Bow Island	4	13	10.0
Manyberries	Bow Island	6	20	19.0
Peace River Composite				
Belloy	Gething	1	3	15.2
	Mississippian	0	1	3.6
Dunvegan	Peace River	1	2	2.8
Eaglesham	Peace River	0	2	2.8
	Mississippian	1	2	4.5
Gordondale	Peace River	5	15	3.8
Hamelin Creek	Peace River	0	3	3.8
	Gething	2	7	19.0
Pouce Coupe	Peace River	6	18	14.0
	Gething	1	2	14.2
Rycroft	Gething Unassoc.	1	1	30.8
	Assoc.	1	1	11.6
Tangent	Peace River	2	12	7.6
	Gething	1	22	4.8
	Triassic	2	14	12.3
Whitelaw	Gething	4	20	7.6
	Triassic	0	7	6.7
Total		28	132	8.8

Table D-5

The Petroleum and Natural Gas Conservation Board

ILLUSTRATIVE DELIVERABILITY SCHEDULE FOR THE AREA TRIBUTARY TO THE CANADIAN WESTERN NATURAL GAS COMPANY LIMITED SYSTEM

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
	Total Requirements			Turner Valley			Jumping Pound			Foremost			Residual Requirements			
YEAR	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent	Bow Island Peak MMCFD	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent
1953	27.8	181	42	19.7	95	56.8	7.9	31	70	0.2	14.0	3.9	41.0			
1954	30.0	196	42	18.0	95	51.8	11.8	46	70	0.2	13.9	3.9	41.1			
1955	31.6	206	42	17.1	95	49.3	14.3	56	70	0.2	13.8	4.0	41.2			
1956	33.0	215	42	17.5	95	50.4	15.3	60	70	0.2	13.7	4.0	41.3		5	
1957	34.8	227	42	17.7	95	51.0	15.3	60	70	0.2	13.6	4.0	41.4	1.6	17	25.8
1958	36.4	237	42	17.7	95	51.0	15.3	60	70	0.2	13.6	4.0	41.4	3.2	27	32.5
1959	37.8	247	42	15.6	84	51.0	15.3	60	70	0.2	13.5	4.1	41.5	6.7	48	38.2
1960	39.6	258	42	15.6	84	51.0	15.3	60	70	0.2	13.4	4.1	41.6	8.5	59	39.5
1961	40.7	265	42	15.3	82	51.0	15.3	60	70	0.2	13.3	4.1	41.7	9.9	68	39.9
1962	41.3	269	42	15.3	82	51.0	14.8	58	70	0.2	13.2	4.1	41.8	11.0	74	40.7
1963	42.0	274	42	15.3	82	51.0	14.3	56	70	0.2	13.1	4.2	41.9	12.2	81	40.8
1964	42.8	279	42	15.3	82	51.0	13.8	54	70	0.2	13.0	4.2	42.0	13.5	88	42.0
1965	43.7	285	42	15.3	82	51.0	13.3	52	70	0.2	12.9	4.2	42.1	14.9	96	43.7
1966	44.5	290	42	15.3	82	51.0	12.5	49	70	0.2	12.9	4.2	42.1	16.5	104	43.5
1967	45.4	296	42	15.3	82	51.0	12.0	47	70	0.2	12.8	4.3	42.2	17.9	112	43.7
1968	46.4	303	42	14.8	79	51.0	11.2	44	70	0.2	12.7	4.3	42.3	20.2	125	44.2
1969	47.3	309	42	13.2	71	51.0	10.7	42	70	0.2	12.6	4.3	42.4	23.2	141	45.1
1970	48.3	315	42	12.1	65	51.0	9.9	39	70	0.2	12.5	4.4	42.5	26.1	156	45.7
1971	48.9	319	42	10.8	58	51.0	9.4	37	70	0.2	12.4	4.4	42.6	28.5	169	46.3
1972	49.6	324	42	10.1	54	51.0	8.9	35	70	0.2	12.3	4.4	42.7	30.4	180	46.3
1973	50.4	329	42	9.3	50	51.0	8.4	33	70	0.2	12.2	4.5	42.8	32.5	191	46.7
1974	51.1	333	42	6.9	37	51.0	7.9	31	70	0.2	12.1	4.5	42.9	36.1	210	47.2
1975	51.8	338	42	5.6	30	51.0	7.4	29	70	0.2	12.1	4.5	42.9	38.6	224	47.3
1976	52.7	344	42	4.8	26	51.0	7.1	28	70	0.2	12.0	4.5	43.0	40.6	235	47.3
1977	53.4	348	42	4.3	23	51.0	6.6	26	70	0.2	11.9	4.6	43.1	42.3	244	47.6
1978	54.3	354	42	3.9	21	51.0	6.4	25	70	0.2	11.8	4.6	43.2	43.8	253	47.4
1979	55.1	359	42	3.4	18	51.0	5.9	23	70	0.2	11.7	4.7	43.3	45.6	263	47.4
1980	55.8	364	42	2.8	15	51.0	5.6	22	70	0.2	11.6	4.7	43.4	47.2	272	47.5
1981	56.7	370	42	2.4	13	51.0	5.4	21	70	0.2	11.5	4.8	43.5	48.7	281	47.4
1982	57.5	375	42	2.2	12	51.0	5.1	20	70	0.2	11.4	4.8	43.6	50.0	288	47.5
TOTAL	1350.7			352.6			322.4			6.0				669.7		
Established Reserves Available for Disposition				370			375			21			16			
Percentage Withdrawn				95			86			29			0			

Table D-6

The Petroleum and Natural Gas Conservation Board

POSSIBLE SOURCES OF SUPPLY FOR THE RESIDUAL REQUIREMENTS OF THE AREA TRIBUTARY TO THE CANADIAN WESTERN NATURAL GAS COMPANY LIMITED SYSTEM

1	2	3	4	5	6	7
Name of Field	Disposable Reserves B.C.F.	Maximum Deliverability at Full Development MMCFD.	Pipeline Miles to Calgary	Reserves Per Pipeline Mile B.C.F./Mile	Maximum Deliverability Per Mile MMCFD./Mile	Remarks
Okotoks	100	14.4	20	5.0	0.72	Good source.
Neapolis	5	5.4	45	0.11	0.12	Poor source.
Olds	40	7.3	50	0.80	0.15	Poor source, except in Homeglen Composite.
Sylvan Lake	25	5.0	85	0.29	0.06	Poor source, except in Homeglen Composite.
Countess	60	4.8	85	0.71	0.06	Poor source, except in Cessford Composite.
Duchess	13	6.1	95	0.14	0.06	Poor source, except in Cessford Composite.
Cessford	965	361.0	100	9.65	3.61	Good source, better in Cessford Composite.
Nevis	410	106.0	100	4.10	1.06	Fair source, better in Homeglen Composite.
Patricia	10	0.95	110	0.09	0.01	Poor source, except in Cessford Composite.
Homeglen Rimbey	500	266.0	115	4.35	2.32	Good source, better in Homeglen Composite.
Princess Steveville Denhart	175	69.0	115	1.52	0.60	Poor source, except in Cessford Composite.
Pincher Creek	2000	333.0	125	16.0	2.58	Good source, except for load factor problem.
Hamilton Lake-Watt Lake	48	26.0	145	0.33	0.18	Poor source.
Oyen Sibbald	48	31.5	160	0.30	0.20	Poor source.
Medicine Hat Residual (1)	232	22.0	175	1.33	0.13	Poor source.
Provost	94	48.5	180	0.52	0.27	Poor source.
Cessford Composite	1223	442.0	115	10.67	3.84	Good source.
Homeglen Composite	950	379.0	120	7.9	3.16	Good source.
Pakowki Lake Composite (including Etzikom and Manyberries)	334(2)	191.0	200	1.67	0.95	Poor source.

(1) Medicine Hat after allowance for local market.

(2) 366 less 32 presently committed to export.

Table D-7

The Petroleum and Natural Gas Conservation Board

ILLUSTRATIVE DELIVERABILITY SCHEDULE FOR THE RESIDUAL REQUIREMENTS OF THE CANADIAN WESTERN NATURAL GAS SYSTEM
(USING CESSFORD COMPOSITE)

1	2	3	4	5	6	7	8	9	10	11	12	13
	Residual Requirements			Okotoks			Cessford Composite			Deficiencies		
Year	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent
1953												
1954												
1955												
1956		5						5				
1957	1.6	17	25.8	3.3	11.2	80	0.3	5.8	14.1	-2.0		
1958	3.2	27	32.5	3.3	11.2	80	1.0	15.8	17.3	-1.1		
1959	6.7	48	38.2	3.3	11.2	80	3.4	26.8	34.8			
1960	8.5	59	39.5	3.3	11.2	80	5.2	47.8	29.9			
1961	9.9	68	39.9	3.3	11.2	80	6.6	56.8	32.0			
1962	11.0	74	40.7	3.3	11.2	80	7.7	62.8	33.6			
1963	12.2	81	40.8	3.3	11.2	80	8.9	69.8	35.0			
1964	13.5	88	42.0	3.1	10.7	80	10.4	77.3	36.9			
1965	14.9	96	43.7	3.0	10.4	80	11.9	85.6	38.0			
1966	16.5	104	43.5	2.9	9.9	80	13.6	94.1	39.5			
1967	17.9	112	43.7	2.8	9.6	80	15.1	102.4	40.4			
1968	20.2	125	44.2	2.7	9.3	80	17.5	107.5	44.6			
1969	23.2	141	45.1	2.6	8.9	80	20.6	132.1	42.6			
1970	26.1	156	45.7	2.5	8.6	80	23.6	147.4	43.7			
1971	28.5	169	46.3	2.4	8.2	80	26.1	160.8	44.3			
1972	30.4	180	46.3	2.3	7.9	80	28.1	170.1	45.2			
1973	32.5	191	46.7	2.2	7.6	80	30.3	183.4	45.2			
1974	36.1	210	47.2	2.1	7.2	80	34.0	202.8	45.7			
1975	38.6	224	47.3	2.1	7.2	80	36.5	216.8	46.0			
1976	40.6	235	47.3	2.0	6.8	80	38.6	228.2	46.3			
1977	42.3	244	47.6	1.9	6.5	80	40.4	237.5	46.7			
1978	43.8	253	47.4	1.8	6.2	80	42.0	246.8	46.7			
1979	45.6	263	47.4	1.8	6.2	80	43.8	256.8	46.7			
1980	47.2	272	47.5	1.7	5.8	80	45.5	266.2	46.8			
1981	48.7	281	47.4	1.6	5.5	80	45.0	264.0	46.8	2.1	11.5	50.1
1982	50.0	288	47.5	1.6	5.5	80	43.0	252.0	46.8	5.4	30.5	48.5
Total	669.7			66.2			599.1			7.5		
Established Reserves Available for Disposition				100			1223					
Percentage Withdrawn				66.2			49.0					

APPENDIX D

Table D-9

The Petroleum and Natural Gas Conservation Board

ILLUSTRATIVE DELIVERABILITY SCHEDULE FOR THE AREA TRIBUTARY TO THE CANADIAN WESTERN NATURAL GAS COMPANY LIMITED SYSTEM

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32
	Total Requirements			Turner Valley			Jumping Pound			Foremost					Okotoks		Homeglen Composite									Deferred Westerose Composite			Deficiencies		
																	Olds			Nevis			Homeglen - Rimbey								
Year	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent	Bow Island Peak MMCFD	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent
1953	27.8	181	42	19.7	95.0	56.9	7.9	31	70	0.2	14.0	3.9	41.0																		
1954	30.0	196	42	18.0	95.0	51.9	11.8	46	70	0.2	13.9	3.9	41.1																		
1955	31.6	206	42	17.1	95.0	49.3	14.3	56	70	0.2	13.8	4.0	41.2																		
1956	33.0	215	42	16.0	95.0	46.1	15.3	60	70	0.2	13.7	4.0	41.3							1.5	5.0	82.0									
1957	34.8	227	42	15.0	95.0	43.3	15.3	60	70	0.2	13.6	4.0	41.4							1.5	10.1*	50.0	2.8	6.9	111.1						
1958	36.4	237	42	13.3	95.0	38.3	15.3	60	70	0.2	13.6	4.0	41.4	3.3	11.2	80				1.5	8.9*	50.0	2.8	6.9	111.1						
1959	37.8	247	42	12.9	93.0	38.0	15.3	60	70	0.2	13.5	4.1	41.5	3.3	11.2	80	1.3	5.0	70	2.0	15.9*	50.0	2.8	6.9	111.1						
1960	39.6	258	42	11.5	91.1	34.6	15.3	60	70	0.2	13.4	4.1	41.6	3.3	11.2	80	1.3	5.0	70	5.2	28.8	50.0	2.8	6.9	111.1						
1961	40.7	265	42	10.4	98.1	29.0	15.3	60	70	0.2	13.3	4.1	41.7	3.3	11.2	80	1.3	5.0	70	7.4	28.8	70.0	2.8	6.9	111.1						
1962	41.3	269	42	8.4	75.3	30.6	14.8	58	70	0.2	13.2	4.1	41.8	3.3	11.2	80	1.3	5.0	70	10.5	57.6	50.0	2.8	6.9	111.1						
1963	42.0	274	42	5.4	82.3	18.0	14.3	56	70	0.2	13.1	4.2	41.9	3.3	11.2	80	1.3	5.0	70	14.7	57.6	70.0	2.8	6.9	111.1						
1964	42.8	279	42	6.7	89.3	20.6	13.8	54	70	0.2	13.0	4.2	42.0	3.3	11.2	80	1.3	5.0	70	14.7	57.6	70.0	2.8	6.9	111.1						
1965	43.7	285	42	5.5	90.9	16.6	13.3	52	70	0.2	12.9	4.2	42.1	3.1	11.7	80	1.3	5.0	70	14.7	57.6	70.0	5.6	13.8	111.1						
1966	44.5	290	42	7.1	98.9	19.7	12.5	49	70	0.2	12.9	4.2	42.1	3.1	10.7	80	1.3	5.0	70	14.7	57.6	70.0	5.6	13.8	111.1						
1967	45.4	296	42	4.5	83.1	14.8	12.0	47	70	0.2	12.8	4.3	42.2	2.9	9.9	80	1.3	5.0	70	14.7	57.6	70.0	9.8	38.4	70.0						
1968	46.4	303	42	6.4	93.4	18.8	11.2	44	70	0.2	12.7	4.3	42.3	2.8	9.6	80	1.3	5.0	70	14.7	57.6	70.0	9.8	38.4	70.0						
1969	47.3	309	42	3.1	82.8	10.3	10.7	42	70	0.2	12.6	4.3	42.4	2.7	9.3	80	1.2	4.7	70	14.7	57.6	70.0	14.7	57.6	70.0						
1970	48.3	315	42	5.0	92.2	14.9	9.9	39	70	0.2	12.5	4.4	42.5	2.6	8.9	80	1.2	4.7	70	14.7	57.6	70.0	14.7	57.6	70.0						
1971	48.9	319	42	6.3	98.9	17.5	9.4	37	70	0.2	12.4	4.4	42.6	2.5	8.6	80	1.1	4.3	70	14.7	57.6	70.0	14.7	57.6	70.0						
1972	49.6	324	42	4.8	67.9	19.4	8.9	35	70	0.2	12.3	4.4	42.7	2.4	8.2	80	1.1	4.3	70	14.7	57.6	70.0	17.5	96.0	50.0						
1973	50.4	329	42	3.6	78.7	12.5	8.4	33	70	0.2	12.2	4.5	42.8	2.3	7.9	80	1.0	3.9	70	13.9	54.5	70.0	21.0	96.0	60.0						
1974	51.1	333	42	4.0	88.5	12.4	7.9	31	70	0.2	12.1	4.5	42.9	2.2	7.6	80	1.0	3.9	70	13.0	51.0	70.0	22.8	96.0	65.0						
1975	51.8	338	42	4.1	93.5	12.1	7.4	29	70	0.2	12.1	4.5	42.9	2.1	7.2	80	0.9	3.5	70	12.1	47.4	70.0	24.5	96.0	70.0	0.5	6.4	21.4			
1976	52.7	344	42	5.0	90.0	15.2	7.1	28	70	0.2	12.0	4.5	43.0	2.1	7.2	80	0.9	3.5	70	11.2	43.9	70.0	24.5	96.0	70.0	1.7	20.4	22.8			
1977	53.4	348	42	5.9	90.0	18.0	6.6	26	70	0.2	11.9	4.6	43.1	2.0	6.8	80	0.9	3.5	70	10.4	40.7	70.0	24.5	96.0	70.0	2.9	30.0	26.4			
1978	54.3	354	42	6.8	90.0	20.7	6.4	25	70	0.2	11.8	4.6	43.2	1.9	6.5	80	0.8	3.1	70	9.8	38.4	70.0	24.5	96.0	70.0	3.9	40.0	26.7			
1979	55.1	359	42	7.7	90.0	23.4	5.9	23	70	0.2	11.7	4.7	43.3	1.8	6.2	80	0.8	3.1	70	9.2	36.0	70.0	24.5	96.0	70.0	5.0	49.7	27.6			
1980	55.8	364	42	8.6	85.0	27.7	5.6	22	70	0.2	11.6	4.7	43.4	1.8	6.2	80	0.8	3.1	70	8.7	34.1	70.0	24.5	96.0	70.0	5.6	62.6	24.5			
1981	56.7	370	42	9.5	75.0	34.7	5.4	21	70	0.2	11.5	4.8	43.5	1.7	5.8	80	0.7	2.7	70	8.2	31.5	70.0	24.5	96.0	70.0	6.5	80.0	22.3	—	3	—
1982	57.5	375	42	10.4	65.0	43.8	5.1	20	70	0.2	11.4	4.8	43.6	1.6	5.5	80	0.7	2.7	70	7.6	29.3	70.0	23.5	92.0	70.0	8.4	76.5	30.1	—	29	—
Total	1350.7			262.7			322.4			6.0				64.7			26.1			280.7			353.6			34.5					
Established Reserves Available for Disposition				370.0			375.0			21.0			16.0	100.0			40.0			390.0			500.0			195.0					
Percent Withdrawn				71.0			86.0			29.0			0	64.7			65.0			72.0			70.6			17.7					

* Includes Small Amount of Cretaceous Peak Gas.

APPENDIX D

Table D-10

The Petroleum and Natural Gas Conservation Board

ILLUSTRATIVE DELIVERABILITY SCHEDULE TO MEET THE REQUIREMENTS OF THE PEACE RIVER AREA

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
	Peace River Area of Alberta Requirements			Present Export Commitments Dawson Creek			Present Export Commitments West Coast Transmission Co. Ltd.			Total of Requirements and Present Commitments			Peace River Composite			Excess Gas Available		
Year	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent
1953	0.3	2.1	40	0.3	2.1	40				0.6	4.1	40.0	0.6	4.1	40.0			
1954	0.8	5.5	40	0.3	2.1	40				1.1	7.6	40.0	1.1	7.6	40.0			
1955	1.2	8.2	40	0.3	2.1	40	42.0	165	69.7	43.5	175.3	68.0	43.5	175.3	68.0			
1956	1.6	11.0	40	0.3	2.1	40	42.0	165	69.7	43.9	178.1	67.5	43.9	178.1	67.5			
1957	2.0	13.7	40	0.4	2.7	40	42.0	165	69.7	44.4	181.4	67.1	44.4	181.4	67.1			
1958	2.4	16.5	40	0.4	2.7	40	42.0	165	69.7	44.8	184.2	66.5	44.8	184.2	66.5			
1959	2.8	19.2	40	0.4	2.7	40	42.0	165	69.7	45.2	186.9	66.2	45.2	186.9	68.4			
1960	3.2	21.9	40	0.4	2.7	40				3.6	24.6	40.0	40.2	169.0	65.0	36.6	144.4	69.7
1961	3.3	22.6	40	0.4	2.7	40				3.7	25.3	40.0	36.2	152.0	65.0	32.5	126.7	70.3
1962	3.4	23.3	40	0.4	2.7	40				3.8	26.0	40.0	32.2	136.0	65.0	28.4	110.0	70.8
1963	3.4	23.3	40	0.4	2.7	40				3.8	26.0	40.0	29.4	124.0	65.0	25.6	98.0	71.0
1964	3.5	24.0	40	0.4	2.7	40				3.9	26.7	40.0	26.5	111.7	65.0	22.6	85.0	73.0
1965	3.7	25.3	40	0.5	3.4	40				4.2	28.7	40.0	24.0	101.0	65.0	19.8	72.3	75.1
1966	3.7	25.3	40	0.5	3.4	40				4.2	28.7	40.0	21.6	91.0	65.0	17.4	62.3	76.5
1967	3.9	26.7	40	0.5	3.4	40				4.4	30.1	40.0	19.4	82.0	65.0	15.0	51.9	79.3
1968	3.9	26.7	40	0.5	3.4	40				4.4	30.1	40.0	17.5	73.8	65.0	13.1	43.7	82.2
1969	4.0	27.4	40	0.5	3.4	40				4.5	30.8	40.0	10.6	49.4	58.9	6.1	18.6	90.0
1970	4.1	28.1	40	0.5	3.4	40				4.6	31.5	40.0	4.6	31.5	40.0			
1971	4.1	28.1	40	0.5	3.4	40				4.6	31.5	40.0	4.6	31.5	40.0			
1972	4.2	28.8	40	0.5	3.4	40				4.7	32.3	40.0	4.7	32.3	40.0			
1973	4.4	30.1	40	0.5	3.4	40				4.9	33.5	40.0	4.9	33.5	40.0			
1974	4.5	30.8	40	0.5	3.4	40				5.0	34.2	40.0	5.0	34.2	40.0			
1975	4.5	30.8	40	0.5	3.4	40				5.0	34.2	40.0	5.0	34.2	40.0			
1976	4.6	31.5	40	0.5	3.4	40				5.1	34.9	40.0	5.1	34.9	40.0			
1977	4.6	31.5	40	0.5	3.4	40				5.1	34.9	40.0	5.1	34.9	40.0			
1978	4.7	32.2	40	0.5	3.4	40				5.2	35.6	40.0	5.2	35.6	40.0			
1979	4.8	32.8	40	0.5	3.4	40				5.3	36.2	40.0	5.3	36.2	40.0			
1980	4.9	33.5	40	0.5	3.4	40				5.4	36.9	40.0	5.4	36.9	40.0			
1981	4.9	33.5	40	0.5	3.4	40				5.4	36.9	40.0	5.4	36.9	40.0			
1982	5.1	34.9	40	0.5	3.4	40				5.6	38.3	40.0	5.6	38.3	40.0			
Total	106.5			13.4			210.0			329.9			547.0			217.1		
Established Reserves Available for Disposition													580.6					
Percent Withdrawn													94.2					

Table D-11

The Petroleum and Natural Gas Conservation Board

ILLUSTRATIVE DELIVERABILITY SCHEDULE FOR REQUIREMENTS OF CANADIAN MONTANA GAS COMPANY LIMITED

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
	Montana Power Commitment			Pakowki Composite			Manyberries			Etzikom			Excess Gas Available		
Year	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent
1953	9.8	40	67	9.8	40.0	67									
1954	10.0	40	68	15.0	58.6	70							5.0	18.6	74
1955	10.0	40	68	10.7	42.2	70	3.0	11.7	70	2.8	11.0	70	6.5	24.9	77
1956	2.5	40	68	11.0	46.5	65	3.1	12.9	65	2.9	12.1	65	14.5	71.5	56
1957				11.3	52.6	59	3.1	14.6	59	3.0	13.8	59	17.4	81.0	59
1958				11.4	57.0	55	3.2	15.8	55	3.0	14.9	55	17.6	87.7	55
1959				11.7	64.0	50	3.2	17.7	50	3.1	16.8	50	18.0	98.5	50
1960				11.8	65.6	49	3.2	18.2	49	3.1	17.2	49	18.1	101.0	49
1961				11.8	64.6	50	3.3	17.9	50	3.1	17.0	50	18.2	99.5	50
1962				11.8	63.4	51	3.3	17.5	51	3.1	16.6	51	18.2	97.5	51
1963				12.3	67.0	50	3.4	18.5	50	3.2	17.5	50	18.9	103.0	50
1964				13.9	73.5	52	4.1	22.1	51	3.3	17.4	52	21.3	113.0	52
1965				13.1	65.0	55	7.4	38.0	54	3.1	15.5	55	23.6	118.5	55
1966				13.0	64.8	55	6.5	32.5	55	2.8	14.0	55	22.3	111.3	55
1967				11.6	57.8	55	5.1	25.4	55	2.6	12.9	55	19.3	96.1	55
1968				10.3	51.3	55	3.9	19.5	55	2.3	11.5	55	16.5	82.3	55
1969				9.1	45.3	55	3.2	15.5	55	2.1	10.5	55	14.4	71.3	55
1970				8.0	39.9	55	2.5	12.5	55	1.9	9.5	55	12.4	61.9	55
1971				7.1	35.4	55	2.0	10.0	55	1.7	8.5	55	10.8	53.9	55
1972				6.3	31.4	55	1.5	8.0	51	1.6	8.0	55	9.4	47.4	55
1973				5.6	27.9	55				1.5	7.5	55	7.1	35.4	55
1974				4.9	24.4	55				1.3	6.5	55	6.2	30.9	55
1975				4.4	22.0	55				1.2	6.0	55	5.6	28.0	55
Total	32.3			235.9			65.0			52.7			321.3		
Established Reserves Available for Disposition				241.0			65.0			60.0					
Percent Withdrawn				97.8			100.0			87.9					

Table D-12

The Petroleum and Natural Gas Conservation Board

POSSIBLE SOURCES OF SUPPLY FOR LOCAL UTILITY SYSTEMS

Field	Zone	Disposable Reserves B.C.F. Presently Connected	Possible Future Use
Ashmont	Upper Cretaceous		8.0
	Lower Cretaceous		2.0
Athabasca	Lower Cretaceous	7.0	
	Wabamun	5.0	
Bantry - Tilley	Sunburst		10.0
Beynon	Lower Cretaceous		9.0
Bonnyville	Lower Cretaceous	4.0	
Brooks - N.E.	Bow Island	5.0	
	Sunburst	5.0	
Brooks - Tilley	Milk River	19.0	
Castor	Viking		18.0
	Lower Cretaceous		2.0
Daysland	Lower Cretaceous		2.0
Donalda	Viking		8.0
	Lower Cretaceous		2.0
Drumheller	Lower Cretaceous		2.0
	Nisku		4.0
Duvernay	Viking		1.0
Elk Point	Colony	1.0	
Hairy Hills	Viking		3.0
Hanna	Viking		3.1
	Lower Cretaceous		3.8
	Banff		1.4
Holden	Viking		3.0
	Lower Cretaceous		5.0
Lac La Biche	Viking		30.0
	Lower Cretaceous		10.0
Leahurst	Lower Cretaceous		8.0
Lindbergh	Viking	3.0	
	Colony	5.0	
Lloydminster	Lower Cretaceous	7.0	
Oberlin	Viking	0.5	
	Lower Cretaceous	3.0	
Redwater	Viking	10.0	
Rosalind North	Lower Cretaceous		10.0
Royal Park	Lower Cretaceous		2.0
Spedden	Colony		3.0
St. Paul	Lower Cretaceous	3.0	
Suffield	Milk River	19.0	
West Drumheller	Lower Cretaceous		3.0
	Jefferson		16.0
Westlock	Lower Cretaceous		2.0
Wildmere	Lower Cretaceous	6.0	
Willingdon	Viking, Lower Cretaceous and Leduc		4.0
Youngstown	Viking		7.0
Sub-Total		102.5 B.C.F.	182.3 B.C.F.
Total		285 B.C.F.	

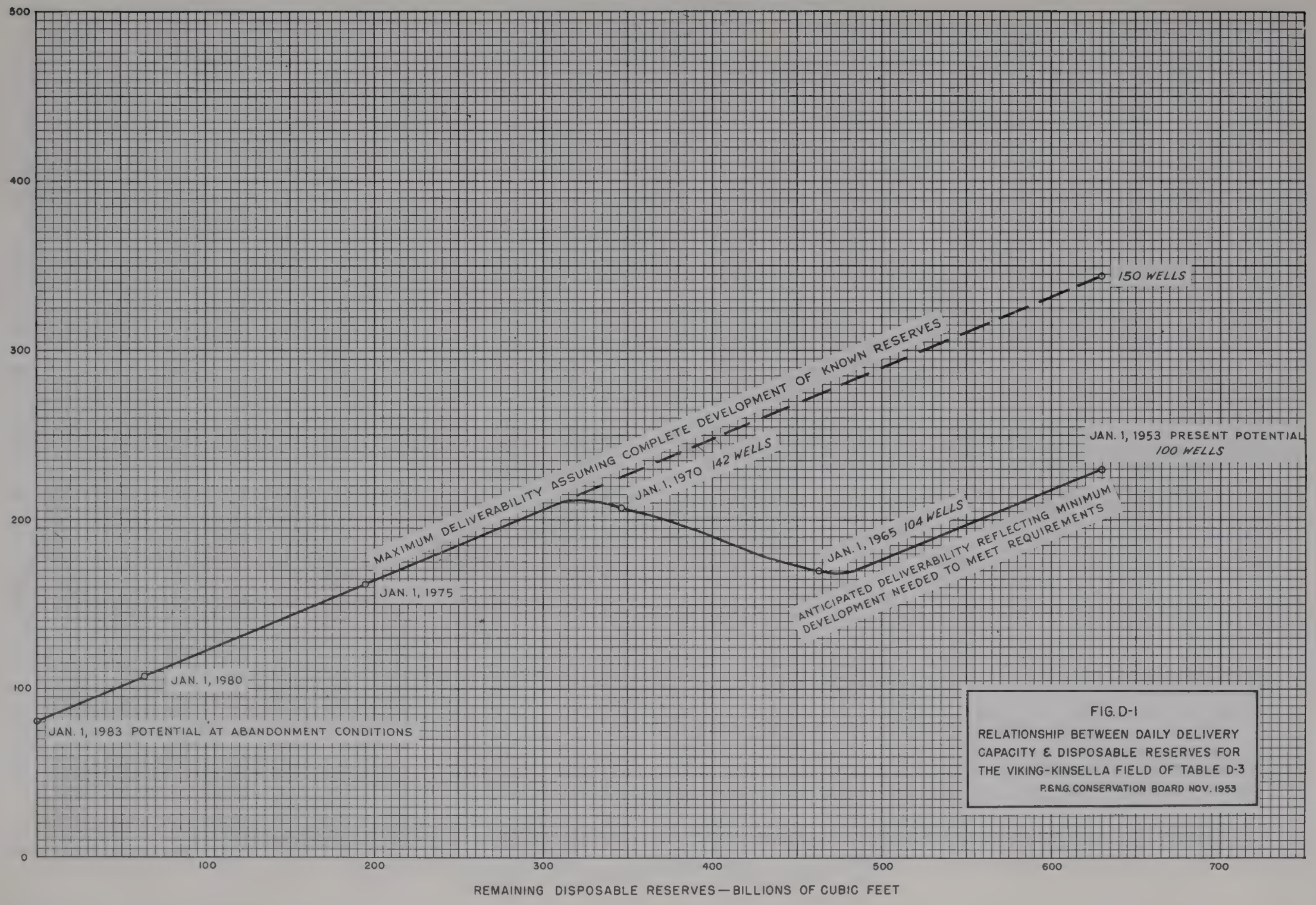


FIG. D-1

RELATIONSHIP BETWEEN DAILY DELIVERY CAPACITY & DISPOSABLE RESERVES FOR THE VIKING-KINSELLA FIELD OF TABLE D-3

P.E.N.G. CONSERVATION BOARD NOV. 1953

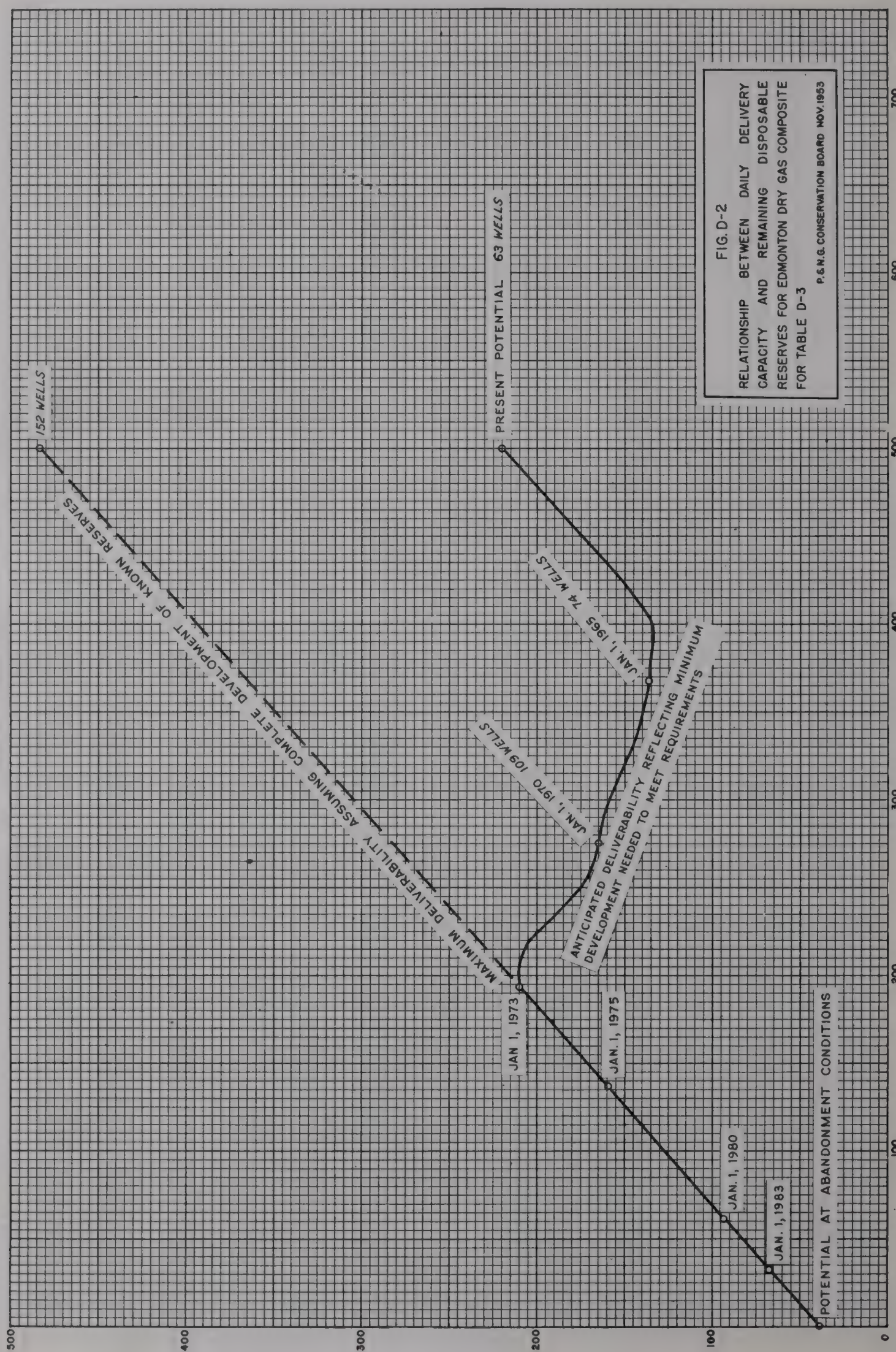


FIG. D-2

RELATIONSHIP BETWEEN DAILY DELIVERY CAPACITY AND REMAINING DISPOSABLE RESERVES FOR EDMONTON DRY GAS COMPOSITE FOR TABLE D-3

P.&N.G. CONSERVATION BOARD NOV. 1953

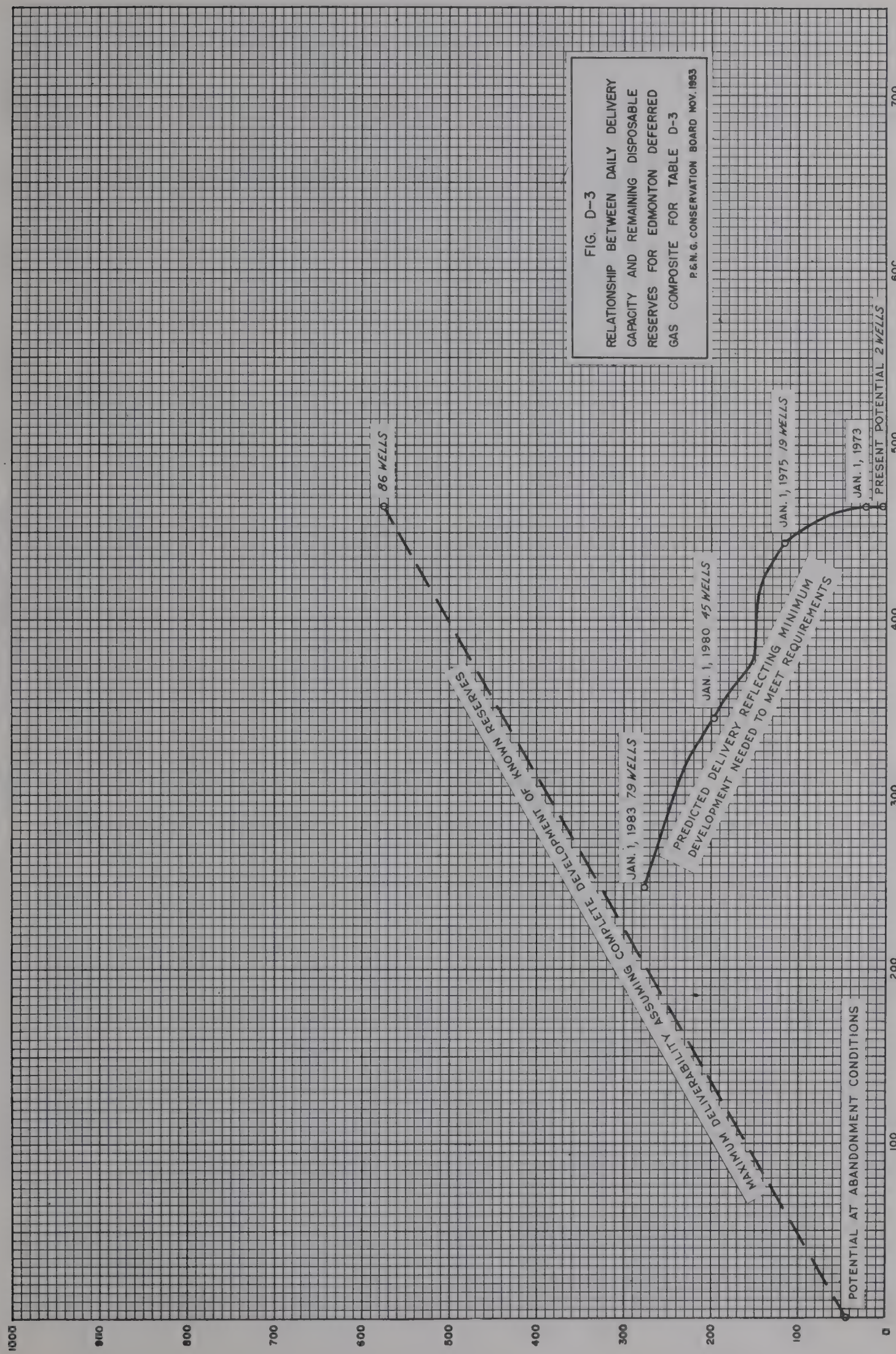


FIG. D-3

RELATIONSHIP BETWEEN DAILY DELIVERY CAPACITY AND REMAINING DISPOSABLE RESERVES FOR EDMONTON DEFERRED GAS COMPOSITE FOR TABLE D-3

P. & N. G. CONSERVATION BOARD NOV. 1953

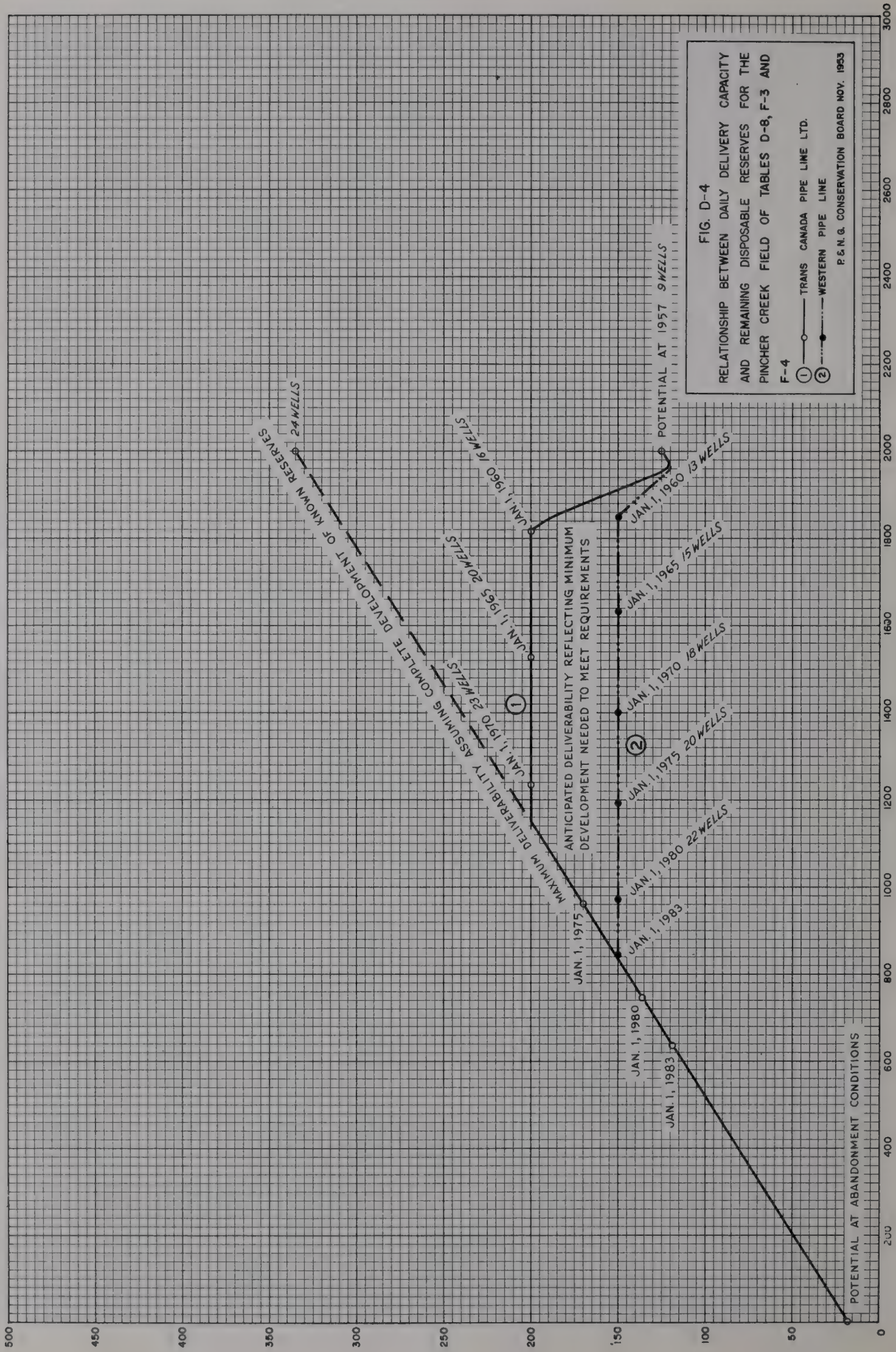


FIG. D-4
RELATIONSHIP BETWEEN DAILY DELIVERY CAPACITY AND REMAINING DISPOSABLE RESERVES FOR THE PINCHER CREEK FIELD OF TABLES D-8, F-3 AND F-4
① TRANS CANADA PIPE LINE LTD.
② WESTERN PIPE LINE
P. & N. G. CONSERVATION BOARD NOV. 1953
DELIVERY CAPACITY — MMCFD MARKETABLE GAS
REMAINING DISPOSABLE RESERVES — BILLIONS OF CUBIC FEET
POTENTIAL AT ABANDONMENT CONDITIONS
POTENTIAL AT 1957 9 WELLS
JAN. 1, 1960 16 WELLS
JAN. 1, 1965 20 WELLS
JAN. 1, 1970 23 WELLS
24 WELLS
COMPLETE DEVELOPMENT OF KNOWN RESERVES
ASSUMING
MAXIMUM DELIVERABILITY
JAN. 1, 1960 13 WELLS
JAN. 1, 1965 15 WELLS
JAN. 1, 1970 18 WELLS
JAN. 1, 1975 20 WELLS
JAN. 1, 1980 22 WELLS
JAN. 1, 1983
ANTICIPATED DELIVERABILITY REFLECTING MINIMUM DEVELOPMENT NEEDED TO MEET REQUIREMENTS
JAN. 1, 1975
JAN. 1, 1980
JAN. 1, 1983

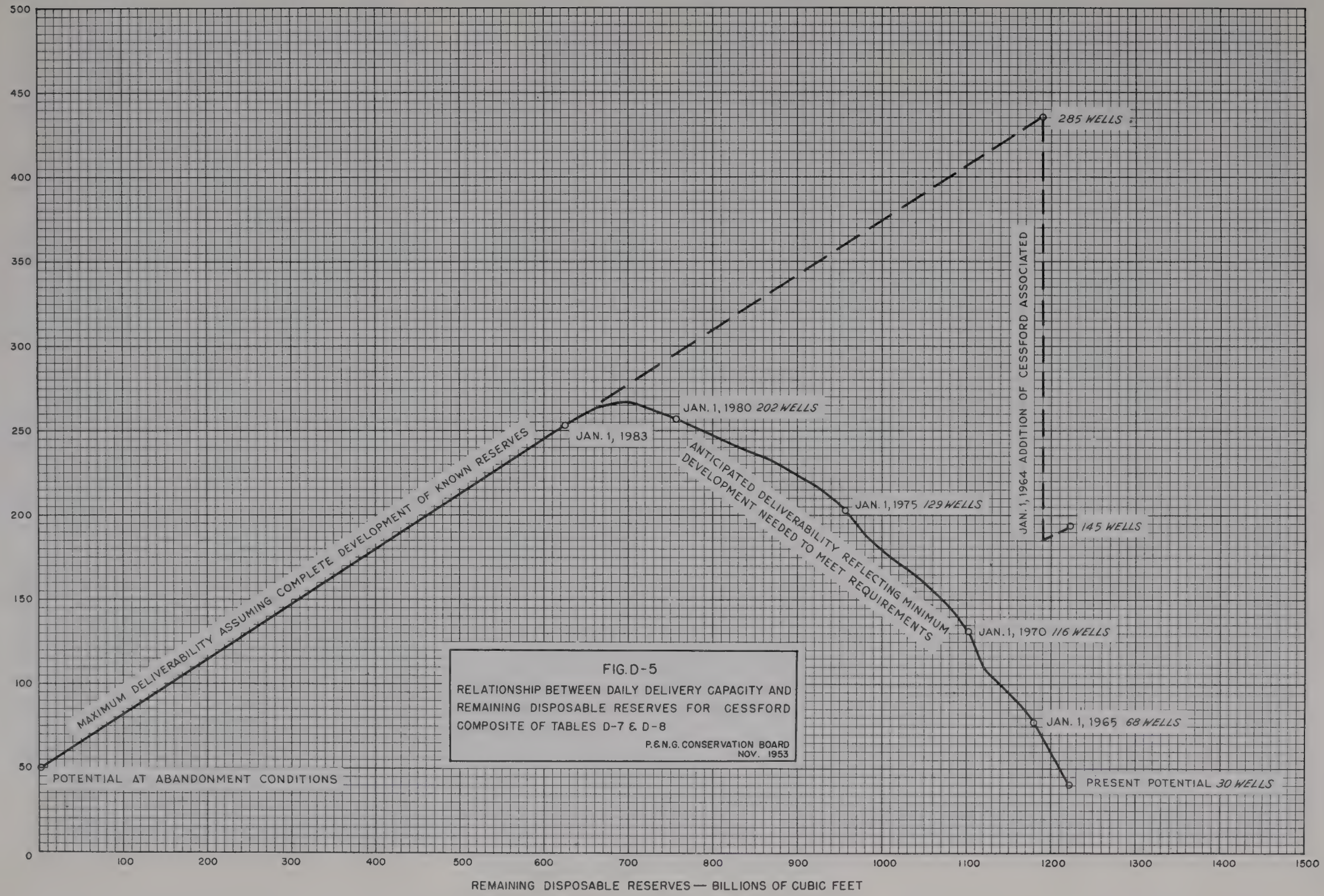


FIG. D-5

RELATIONSHIP BETWEEN DAILY DELIVERY CAPACITY AND REMAINING DISPOSABLE RESERVES FOR CESSFORD COMPOSITE OF TABLES D-7 & D-8

P. & N.G. CONSERVATION BOARD
NOV. 1953

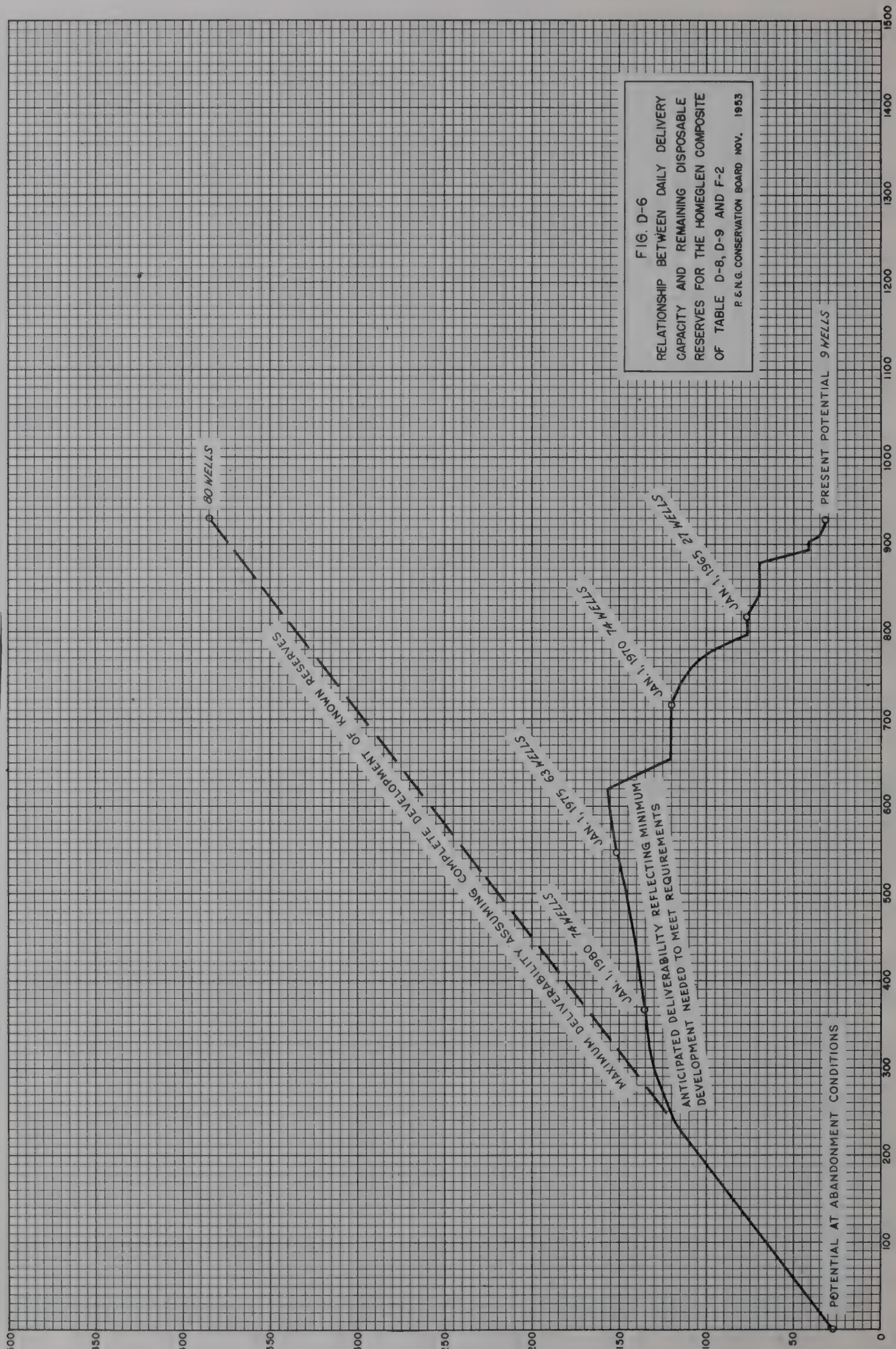


FIG. D-6
RELATIONSHIP BETWEEN DAILY DELIVERY CAPACITY AND REMAINING DISPOSABLE RESERVES FOR THE HOMEGLEN COMPOSITE OF TABLE D-8, D-9 AND F-2
P. & N.G. CONSERVATION BOARD NOV. 1953
DELIVERY CAPACITY — MMCFD MARKETABLE GAS
REMAINING DISPOSABLE RESERVES — BILLIONS OF CUBIC FEET
0
50
100
150
200
250
300
350
400
450
500
100
200
300
400
500
600
700
800
900
1000
1100
1200
1300
1400
1500
POTENTIAL AT ABANDONMENT CONDITIONS
ANTICIPATED DELIVERABILITY REFLECTING MINIMUM DEVELOPMENT NEEDED TO MEET REQUIREMENTS
MAXIMUM DELIVERABILITY ASSUMING COMPLETE DEVELOPMENT OF KNOWN RESERVES
JAN. 1, 1980 74 WELLS
JAN. 1, 1975 63 WELLS
JAN. 1, 1970 74 WELLS
JAN. 1, 1965 12 WELLS
PRESENT POTENTIAL 9 WELLS
STEM 80 WELLS

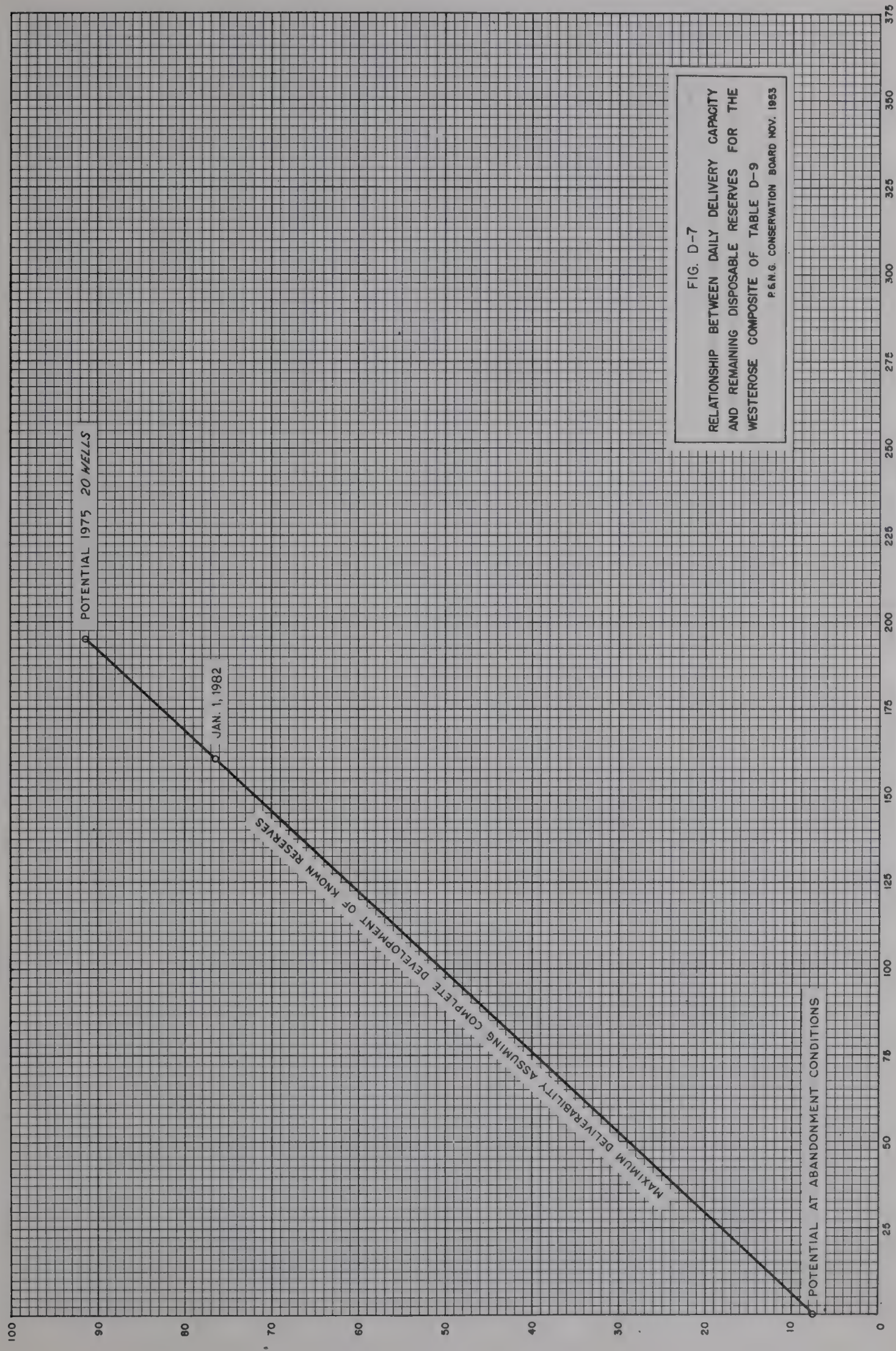


FIG. D-7

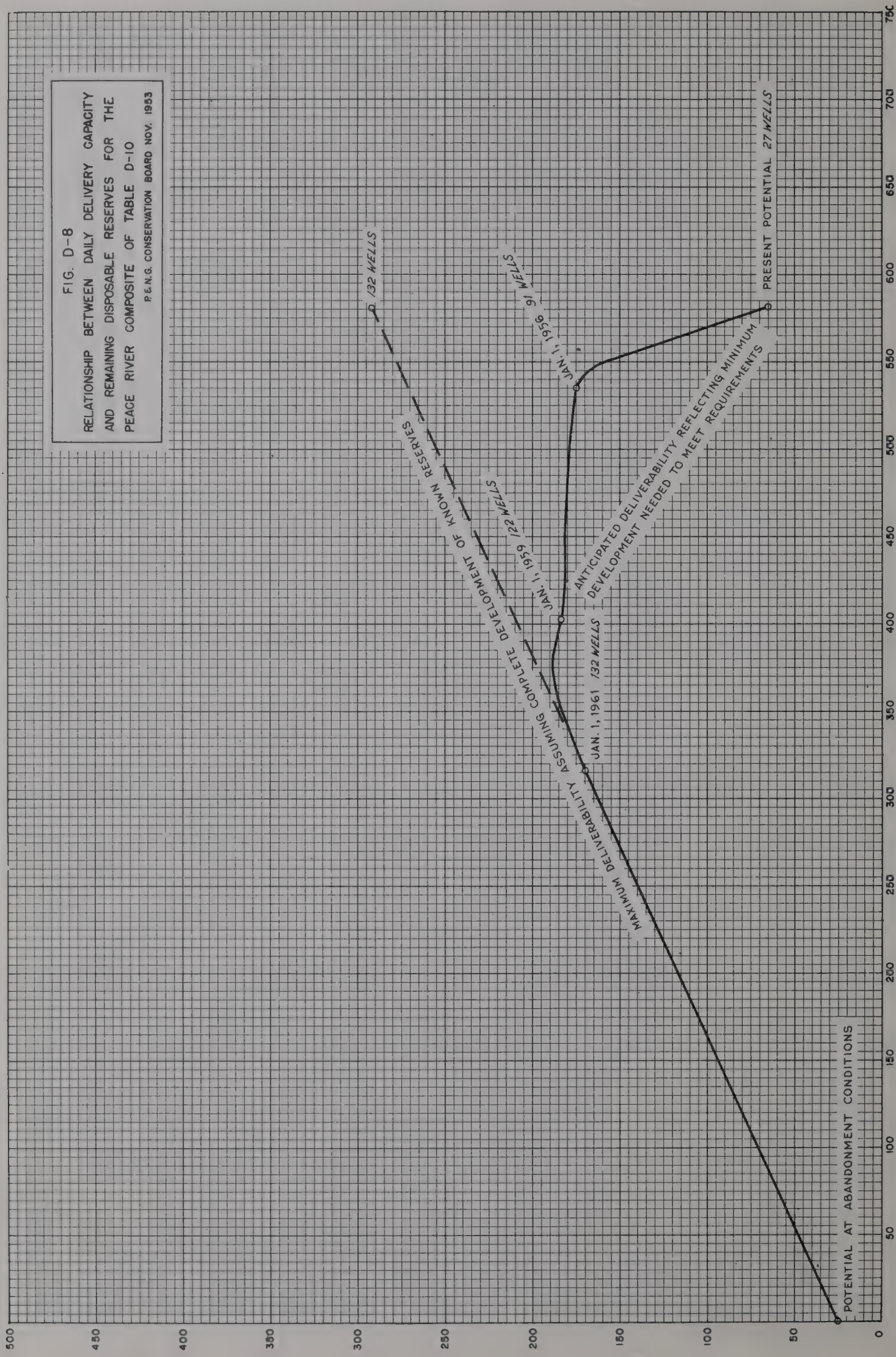
RELATIONSHIP BETWEEN DAILY DELIVERY CAPACITY AND REMAINING DISPOSABLE RESERVES FOR THE WESTEROSE COMPOSITE OF TABLE D-9

P.G.N.G. CONSERVATION BOARD NOV. 1953

FIG. D-8

RELATIONSHIP BETWEEN DAILY DELIVERY CAPACITY AND REMAINING DISPOSABLE RESERVES FOR THE PEACE RIVER COMPOSITE OF TABLE D-10

P. & N.G. CONSERVATION BOARD NOV. 1953



DELIVERY CAPACITY — MMCFD MARKETABLE GAS

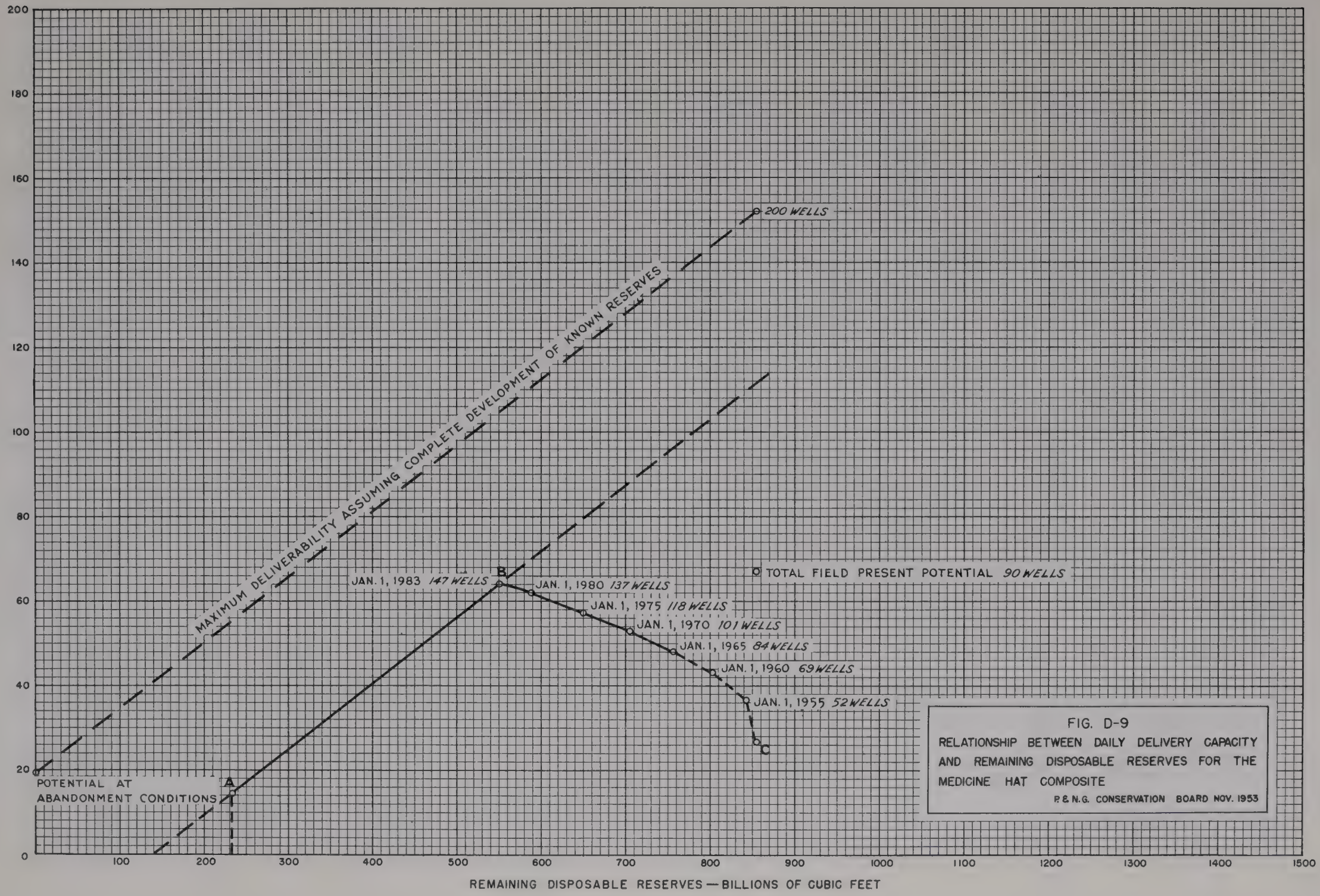
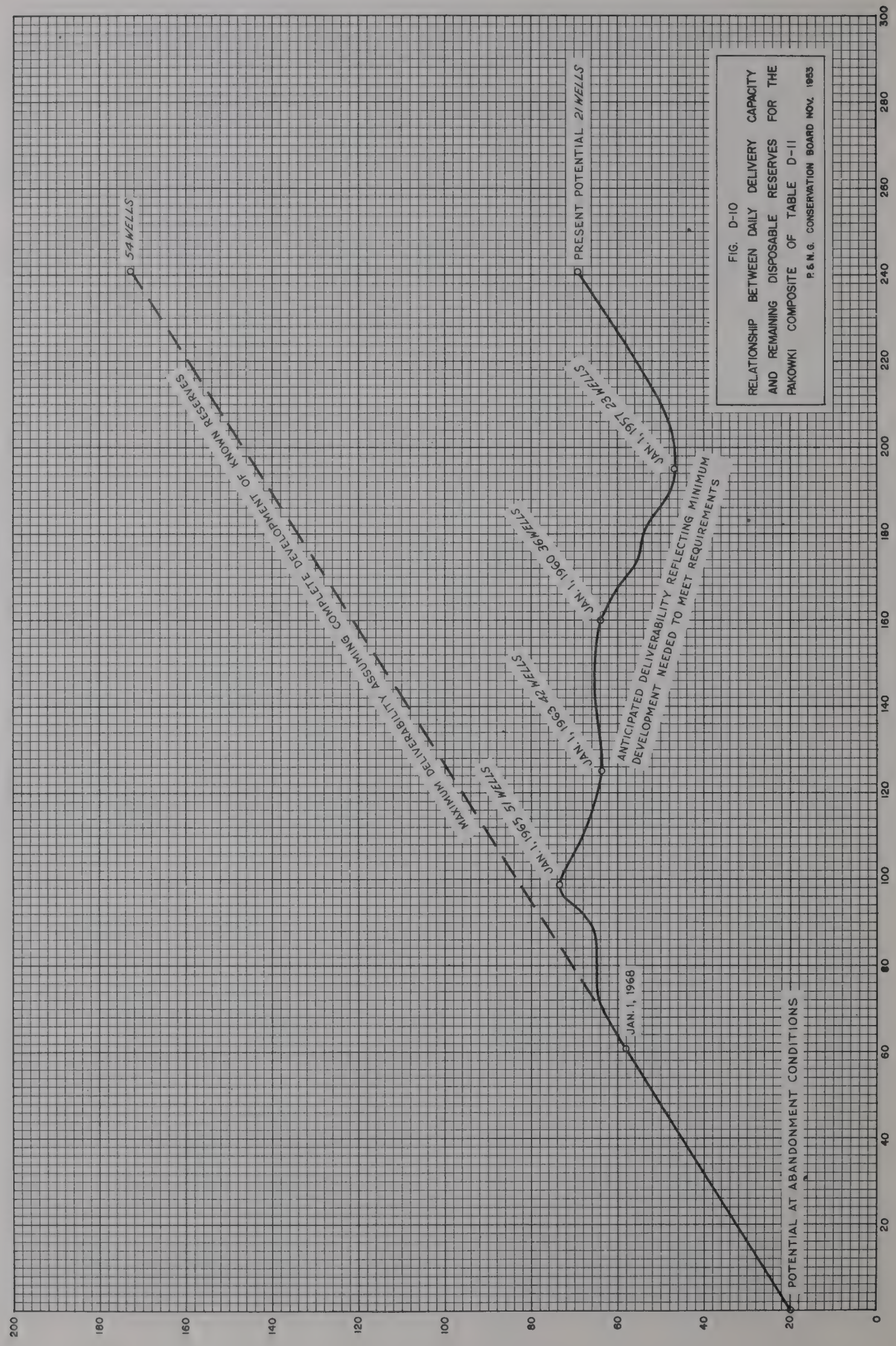


FIG. D-9

RELATIONSHIP BETWEEN DAILY DELIVERY CAPACITY AND REMAINING DISPOSABLE RESERVES FOR THE MEDICINE HAT COMPOSITE

P. & N.G. CONSERVATION BOARD NOV. 1953


DELIVERY CAPACITY — MMCFD MARKETABLE GAS
REMAINING DISPOSABLE RESERVES — BILLIONS OF CUBIC FEET
0
20
40
60
80
100
120
140
160
180
200
220
240
260
280
300
20
40
60
80
100
120
140
160
180
200
54 WELLS
PRESENT POTENTIAL 21 WELLS
JAN. 1, 1957 23 WELLS
JAN. 1, 1960 36 WELLS
JAN. 1, 1963 42 WELLS
JAN. 1, 1965 51 WELLS
MAXIMUM DELIVERABILITY ASSUMING COMPLETE DEVELOPMENT OF KNOWN RESERVES
ANTICIPATED DELIVERABILITY REFLECTING MINIMUM DEVELOPMENT NEEDED TO MEET REQUIREMENTS
JAN. 1, 1968
POTENTIAL AT ABANDONMENT CONDITIONS
FIG. D-10
RELATIONSHIP BETWEEN DAILY DELIVERY CAPACITY AND REMAINING DISPOSABLE RESERVES FOR THE PAKOWKI COMPOSITE OF TABLE D-11
P. & N.G. CONSERVATION BOARD NOV. 1953

APPENDIX E
IN THE MATTER OF THE NATURAL GAS SURPLUS TO THE PRESENT AND FUTURE REQUIREMENTS AND THE PRESENT EXPORT COMMITMENTS OF THE PROVINCE

From Table A-1 showing the established reserves of the Province and from the determination of reserves which the Board has found to be necessary to meet all of the various requirements within the Province and the presently committed export volumes, it is now possible to indicate the present surplus of gas.

Table E-1 following, shows by fields the surplus disposable gas which the Board now finds.

Table E-1

Surplus Gas

Field or Composite	Total Established Reserves B.C.F.	Present Surplus B.C.F.
Peace River Area Reserves		
Peace River Composite	580.6	217.1
Pakowki Lake Area Reserves		
Pakowki Composite	241.0	208.7
Etzikom	60.0	60.0
Manyberries	65.0	65.0
Pakowki Lake Area Total	366.0	333.7
Other Reserves of the Province		
Edmonton Deferred Gas Composite	464.7	25.7
Medicine Hat	855.0	232.0
Pincher Creek	2,000.0	2,000.0
Cessford Composite	1,223.0	1,223.0
Small Reserves		
Clive	15.0	15.0
Big Valley	10.0	10.0
Big Valley. North & Fenn	35.0	35.0
Stettler	18.0	18.0
Erskine	10.0	10.0
Wildunn Creek	15.0	15.0
Other Small Reserves Less Than 10 BCF	50.0	50.0
Sub Total of Small Reserves	153.0	153.0
Total of Other Reserves	4,695.7	3,633.7
Reserves Presently Considered Beyond Economic Reach, Some	800.0	800.0
TOTAL	6,442.3	4,984.5
Less Reserve Required for Local Supply to be supplied by Transmission Line		200.0
TOTAL Surplus Gas		4,784.5
		say 4.8 TCF

The Board declares the above reserves totalling 4.8 TCF to be surplus to the present and future requirements and the present export commitments of the Province. In doing so, however, the Board stresses the fact that it is the above gas, or the equivalent, which is now being called surplus. These quantities of gas are now declared surplus in the light of the estimated requirements and the illustrative deliverability schedule of Tables D-1 to D-12. As mentioned in Appendix D the Board recognizes that future developments will almost certainly call for other arrangements and deliverability programs. The Board is confident that such developments will tend to increase and not to reduce the amount of gas which it can declare surplus but they may well necessitate diversion of some of the above reserves for Provincial use and the substitution of other gas as surplus. Particularly likely is the discovery and development of further oil field gas which will require a place in the market. Other problems involving load factor balancing, peak day deficiencies, market proration, storage, interchangeability etc. may also require the diversion of some of the above gas to Provincial use. In declaring the present surplus, it should be understood that the Board might from time to time substitute other reasonable interchangeable gas for any part of the surplus.

APPENDIX F

IN THE MATTER OF THE EFFICIENT DEVELOPMENT AND UTILIZATION OF THE GAS RESERVES OF THE PROVINCE WITH RESPECT BOTH TO THE PRESENT AND FUTURE REQUIREMENTS OF THE PROVINCE AND THE MARKETS OUTSIDE THE PROVINCE

The Board has given considerable thought to the manner in which the gas reserves of the Province could be best developed and utilized to supply and protect the requirements of the Province and to serve outside markets. From its interpretation of the testimony presented at the hearings together with its own studies on reserves, trends, Provincial requirements and deliverability, the Board is convinced that whatever plan of development and utilization is adopted, that plan should promote:

(a) conservation and the efficient utilization of the gas resources of the Province;

(b) flexibility of development, to the end that any necessary diversion of gas from Provincial to export use—or vice versa—is possible;

(c) access of consumers in the Province to that gas which can be delivered most economically to them;

(d) control of gas within the Province by Provincial authorities;

(e) market sharing or the operation of a market proration plan; and

(f) joint and efficient use of field, plant, pipeline, and other facilities for the mutual benefit of consumers, producers, and distributors.

These convictions indicate to the Board the need for close integration—where economically feasible—between existing and new pipeline systems within the Province. The Board, in other words, is now convinced of the desirability of reasonable interconnection of fields with the pipeline systems serving both the Alberta and the export markets. The degree to which this should be done and the best manner for its accomplishment are matters dependent upon a balance between the cost of interconnection and the benefits to be derived.

Any sound plan for the interconnection of the diverse fields with both internal and external markets must be conceived in the light of:

(a) the location, magnitude and deliverability characteristics of the gas reserves (for discussion on the importance of deliverability characteristics see the 1951 and the 1952 reports of the Board and Appendix D of this report);

(b) the location of areas of the Province most favorable for future gas discoveries;

(c) the location, magnitude and load factor characteristics of the markets within the Province; and

(d) the location (s) on the Provincial border of the "gate (s)" to markets outside the Province and the magnitude and load factor characteristics of those markets.

The importance and role of the above factors on the design of an interconnection scheme is almost self evident. Included within item (a) would be the important matter of conservation of unavoidably produced oil field gas through the assurance of market outlets for it. Also under this category would be need for the provision of high load factor markets for processed gas produced from wet gas fields such as Pincher Creek.

With its thinking guided by these general concepts, the Board has reviewed the details of the design of the various gathering systems advocated by the applicants, Alberta Inter-Field Gas Lines Ltd. and the utility companies. In considering these proposals in the light of the reserves which the Board now declares surplus, it has been found convenient to segregate the fields as shown in Table D-1—i.e., into Peace River Reserves, Pakowki Lake Area Reserves and Other Reserves of the Province. The manner in which each of these groups of reserves could be associated with a comprehensive interconnection scheme is discussed in the following sections.

Peace River Reserves

None of the applicants or other interested parties proposed the interconnection of the Peace River reserves with other reserves in the Province or with markets to be served by them. The Board holds the same opinion it expressed in the 1952 report, "That the Peace River area is remote from other settled areas in the Province and does not lend itself readily to an integrated and province-wide gathering and distributing scheme". The integration and production of these fields is, therefore, considered independently of the balance of the Province.

From Tables D-10 and E-1, it may be seen that of the total Peace River area reserve of 580.6 BCF presently considered within economic reach, some 217 BCF has been declared surplus. Columns 17, 18 and 19 of Table D-10 show the manner in which it is contemplated that the excess gas could be produced commencing in 1960 subsequent to the present initial commitment to the Westcoast Transmission Company Limited.

Pakowki Lake Area Reserves

Canadian-Montana Pipeline Company propose an expansion of its present gathering system (under The Gas Export Act) to collect gas from the Manyberries field with no interconnection to other pipeline systems. Neither Western Pipe Lines nor Alberta Inter-Field Gas Lines Ltd. considered the fields covered by Canadian-Montana Pipeline Company's application proper for inclusion in the gathering systems which they proposed. The Canadian Western Natural Gas Company Limited gave no indication of interest in interconnection of its system with these reserves and, in fact, submitted that any useful connection would require the provision of new pipeline

capacity at high cost. Mr. Trostel, on behalf of Trans-Canada Pipe Lines Limited et al, recommended interconnection between Canadian Western Natural Gas Company Limited and the fields in the Pakowki Lake area and use of these fields by Canadian Western Natural Gas Company Limited but the Board cannot believe that this would be economic from the viewpoint of Alberta consumers. The location, magnitude and deliverability characteristics of these reserves together with their distance from consuming areas of the Province, do not suggest to the Board any economic advantage to their interconnection with other pipeline systems (See Table D-6). In fact, the Board considers the Pakowki Composite (Pendant d'Oreille and Black Butte fields together with the Comrey well) and the Manyberries and Etzikom fields to be a virtually isolated group—at least at the present time. The manner of producing these fields and the pattern of availability of the surplus gas therein is a problem which, at the present time, may be considered separately from the remainder of the Province.

Table E-1 shows that the amount of gas in the Pakowki Composite which is surplus to the present commitment to The Montana Power Company is 208.7 BCF. In addition, in the same area, the reserves of the Etzikom and Manyberries fields in the amounts of 60 BCF and 65 BCF respectively, have been declared surplus giving a total surplus in the Pakowki Lake Area of 333.7 BCF. One method in which the gas could become available is illustrated in Columns 14 to 16 of Table D-11. By assuming different annual withdrawals and different load factors, other figures could be obtained. The method illustrated is actually patterned on the application of the Canadian-Montana Pipeline Company. Of the total surplus (333.7 BCF) some 321 BCF could be produced by 1975.

Other Surplus Reserves of the Province

The Board considers the "Other Surplus Reserves of the Province" (those so listed in Table E-1) to be ones which logically could be considered for inclusion in an interconnection scheme. In the Board's view, an interconnection scheme embracing these surplus reserves and the reserves allocated in Appendix D to meet the requirements of the Province, to supply both Provincial and export markets is reasonable and practical and would offer the advantages discussed earlier.

Proposal of Western Pipe Lines

Western Pipe Lines proposed (for Phase I of its project) a gathering system which in effect interconnected the Pincher Creek, the Cessford Composite and the Medicine Hat fields for the benefit of its export project. While this gathering system would permit interconnection with the Calgary—Bow Island line of Canadian Western Natural Gas Company Limited, it is not a comprehensive overall plan of the type the Board now believes proper. The Western Pipe Lines is designed to meet its export requirements without specific allowance for dovetailing with the requirements of the Province. Moreover, Western Pipe Lines' system makes no provision for the gathering of presently available oil field gas and presumably is based on the assumption that such gas would now serve only the market within the Province.

Western Pipe Lines did, however, indicate its willingness to co-operate with Alberta Inter-Field Gas Lines Ltd. if the proposals of that company met with the approval of the Board. Accordingly, the Board assumes that while Western Pipe Lines did not, itself, submit a fully integrated plan, it does endorse the plan of Alberta Inter-Field Gas Lines Ltd. designed for the Western Pipe Lines export projects.

Trans-Canada Pipe Lines Limited, et al

Trans-Canada Pipe Lines Limited proposed an extensive gathering system to collect gas from Pincher Creek, Medicine Hat, the Cessford Composite fields and a large group of fields in the central part of the Province. This latter group included Nevis, Acheson and smaller fields. It also makes provision for gathering surplus gas from the "Golden Trend".

The Board has found that most of the fields in this group either are not surplus to the present and future requirements of the Province or are beyond economic reach. To illustrate, the reserves of Hanna, Nevis, Acheson, St. Albert, Campbell-Namao, Bon Accord—Lost Point Lake and Legal-Picardville are not surplus and many of these fields must, in the Board's opinion, be connected to one or other of the large consuming areas of the Province. The Trans-Canada plan suggests that these reserves be produced to the export market. The reserves of Craigmyle, Castor, Rochester, Boyle, Mustang, Amisk Lake, Jarvie and some others, are believed by the Board presently to be beyond economic reach.

In view of the foregoing, the Board concludes that the available reserves could not support the northwestward line from the Cessford field proposed by Trans-Canada Pipe Lines Limited.

The remainder of the Trans-Canada Pipe Lines Limited gathering system is somewhat similar to that proposed by Western Pipe Lines. A major point of difference between Trans-Canada Pipe Lines Limited and Western Pipe Lines, however, is that Trans-Canada Pipe Lines Limited expressed strong opposition to the gathering system proposed for them by Alberta Inter-Field Gas Lines Ltd. Trans-Canada Pipe Lines Limited stated that the scheme of Alberta Inter-Field Gas Lines Ltd. would:

(a) increase the cost of gathering the gas required by Trans-Canada Pipe Lines Limited;

(b) make the financing of the Trans-Canada Pipe Lines Limited project more difficult;

(c) result in "disputes over the allocation of costs"; and

(d) result in unnecessary contractual complication.

The Board cannot accept these views as condemning the concept of reasonable interconnection of fields with the pipeline systems serving both the Alberta and the export markets.

Proposal of Canadian Western Natural Gas Company Limited and Northwestern Utilities, Limited

The Board has studied the proposal of the utility companies with respect to the construction of a large diameter transmission line from the Edmonton area to Calgary. As has been discussed in Appendix D, the Board concurs with the view of the utility companies that the most logical sources of supply for the future requirements of the area tributary to the Canadian Western Natural Gas Company system are the fields in the general Homeglen-Rimbey area. A line from these fields to Calgary would appear to be a necessity. The line as proposed would enable the towns between Red Deer and Calgary to be served with natural gas at reasonable rates. It would provide for emergency interchange of gas between the two utility company systems. The line would provide an outlet for undiscovered reserves in the potentially favorable area to the west. While the proposal makes no specific provision for the gathering of oil field gas in the general Stettler area, the lateral serving the Nevis field would facilitate such gathering.

To provide market outlet for excess gas which might be developed along the route of Edmonton—Calgary line, the utility companies propose the future construction of a further line extending southeasterly from Calgary to join the "Pincher Creek export line" to be built by "others". This latter line would connect Pincher Creek, the Cessford Composite and the Medicine Hat fields with an export "gate" on the Saskatchewan border. The location of the east-west export line as shown in Exhibit 67 filed by the utility companies seems unnecessarily far south. The Board believes that the export "gate" should be farther north—about at Township 20 as recommended by Trans-Canada Pipe Lines Limited. Apart from this, however, the Board believes that a combination of physical facilities such as those mentioned above would satisfy the requirements of a reasonable interconnection system. The difference in ownerships and operation proposed by the utility companies for various portions of the system seems unfortunate and hardly conductive to optimum integration to meet Provincial and export requirements. Moreover, it does seem to the Board that if a separately owned interconnection system (if any way similar to that recommended by Alberta Inter-Field Gas Lines Ltd.) has a role in the Province, that role is in the carrying of gas for the accounts both of the local utility companies and the export market. The Board has observed also that the proportion of the capacity of the line north from Calgary which would be used by the utility companies over the next 10 to 15 years is relatively small.

Proposals of Alberta Inter-Field Gas Lines Ltd.

Alberta Inter-Field Gas Lines made proposals for integrated gathering systems, designed to incorporate the fields proposed to be included in either the scheme of Western Pipe Lines or that of Trans-Canada Pipe Lines Limited and interconnecting with the projected lines of the utility companies. By connecting only those fields proposed by the applicants, many of the disadvantages inherent in the other proposals,

remain in the Inter-Field schemes. Alberta Inter-Field Gas Lines Ltd. has, however, gone somewhat further than the applicants in showing how the systems to serve export could be interconnected with the utility company lines.

Accepting the plans of the utility companies, Inter-Field indicates its agreement to the ownership division referred to earlier. On the other hand, Inter-Field propose to construct not only the main transmission line within the Province but also the several laterals to individual fields. The Board agrees with most of the arguments advanced by Inter-Field but does not think it necessarily follows that the "integrated system operator" should construct the lateral lines to individual fields.

Trunk-Line System

The Board is of the view that the advantages and the disadvantages of the several schemes proposed may be best reconciled through the creation of a Trunk-Line system operating in conjunction with field lateral lines and acting as a common carrier under complete Provincial jurisdiction. The Board believes that the system itself need only include the main or trunk-lines which appear in any event to be necessary to serve the Province and export markets to the east. The Trunk-Line would extend from the Edmonton area to Calgary (as proposed by the utility companies) and then easterly to the export "gate" at the Saskatchewan border. Lateral lines from the fields could be built by the producers, the utility companies, the export companies or by the Trunk-Line system itself.

The general route of the Trunk-Line is shown schematically in Figure F-1. The line is routed reasonably directly except for slight deflections towards the larger reserves. Preliminary design of the trunk line to suit the anticipated volumes in the year 1965 indicates that the Edmonton area—Calgary portion would have an equivalent diameter of about 24 inches and would cost 10 or 11 million dollars while the portion east of Calgary would have an equivalent diameter of about 30 inches and would cost some 16 to 17 million dollars.

The Board has estimated the average transmission costs over the period 1956-1965 inclusive, as follows:

(a) Average gathering costs from fields to the Trunk-Line—some 1.4 MCF

(b) Average Trunk-Line costs for delivery to the eastern export gate—some 3.2 MCF

(c) Total average transport costs from fields to the eastern export gate—some 4.6 MCF.

These transmission costs are preliminary figures but believed to be within 10 or 15 per cent of what the actual costs would be.

The line could operate either as a common carrier or as both a common carrier and a common purchaser. Operation as a common carrier would permit full realization of pipeline economics through planned joint use of the facilities. At the same time it would leave to the producer and the local or export purchaser the matter of negotiation of the terms of the sale and purchase—subject to Provincial regulations.

To properly assess the value of an integrated system based on the Trunk-Line, illustrative deliverability schedules have been compiled to indicate the manner in which Alberta's requirements could be met while supplying gas to an easterly export line. In Table F-1 the requirements of the areas tributary to the Northwestern Utilities, Limited system and the Canadian Western Natural Gas Company Limited system have been combined with one-third of the local requirements (that portion to be supplied by a transmission line).

Table F-2 shows the manner in which certain fields could be produced under the integrated scheme. These fields are ones which the Board would expect to be produced in a manner independent of the size of an eastern export market. Columns 5, 6 and 7 show the manner in which the oil field gas in Edmonton area would be available. This is the same as that shown in Columns 5, 6 and 7 of Table D-3. It should be noted, however, that the integrated system would enable the high load factor oil field gas (which in the summer months may be produced in volumes in excess of the Northwestern Utilities, Limited market) to reach another market; i.e., to share in the export market. This could eliminate the necessity of storage or flaring in those fields.

Columns 8, 9 and 10 of Table F-2 indicate the projected deliveries from the Turner Valley field under the Trunk-Line integration. The advantage of the scheme to this field may be seen by comparing the above columns with Columns 5, 6 and 7 of Table D-9. Under integration the load factor would be substantially increased and the total 30 year withdrawals increased from 70 per cent of the total reserves to 95 per cent.

The projections of Jumping Pound, Olds, Nevis and Homeglen-Rimbey fields as shown in Columns 11, 12, 13 and 21 to 29 inclusive, of Table F-2 have been made at load factors of 80 per cent instead of 70 per cent as was required without integration. Intergration allows these fields to share in the higher load factors of an export market. This is particularly desirable in view of the current high capital costs of processing plants.

Columns 30, 31 and 32 indicate the residual requirements of the combined systems after connection of the fields shown.

Table F-3 and F-4 contain illustrative deliverability schedules designed to indicate the manner in which the balance of the available reserves could be produced under an integrated plan to serve one or the other of the proposed easterly export schemes. The two tables are similar in that they show the projections of the Pincher Creek field and of a composite of all the remaining available fields in the area. These remaining fields include all of the dry gas fields and the deferred oil field gas referred to in Appendix D. The basic deliverability data for them are shown in Table F-5.

Table F-3 shows the manner in which the fields would be produced to make gas available to meet the requirements of Trans-Canada Pipe Lines Limited. Columns 5, 6 and 7 project the volumes of gas to be made available from the Pincher Creek field and reflect the installation of a maximum economic sized plant of 200 MMCFD

by 1959. The deliverability from this field is shown by curve 1 of Figure D-4. The total withdrawal from Pincher Creek over the 30 year period would be some 1,363 BCF or 68 per cent of the established reserve.

Columns 8, 9 and 10 indicate the manner in which gas would be available from the composite of the remaining fields. The deliverability reserve relationship is shown in Figure F-2. Columns 11, 12 and 13 show the surplus gas available from the Trunk-Line system if this surplus is scheduled to suit the requirements of Trans-Canada Pipe Lines Limited as projected by Mr. Trostel. These figures indicate that after fully providing for the requirements of the Province, those of Trans-Canada Pipe Lines Limited could be met until 1978 when slight annual and peak day deficiencies would occur. For all practical purposes, and having in mind the trends in the growth of the reserves, it can be concluded that the requirements of Trans-Canada Pipe Lines Limited could be met in a realistic manner through the Trunk-Line and field lateral facilities.

Table F-4 is the counterpart of Table F-3 but designed to meet the requirements of Western Pipe Lines. Columns 5, 6 and 7 indicate the construction of a minimum economic sized plant of 150 MMCFD at Pincher Creek. This deliverability is illustrated by Curve 2 of Figure D-4 the total withdrawal over the thirty year period would be approximately 1,160 BCF or 58 per cent of the reserve. Columns 8, 9 and 10 show the projected withdrawals from the composite fields whose basic deliverability data are shown in Table F-5: The deliverability-reserve relationship employed is illustrated in Figure F-3. The total withdrawal from these fields is 2,065 BCF or 57 per cent of the established reserve compared to 3,076 BCF or 85 per cent in the case of meeting Trans-Canada Pipe Lines' requirements.

Columns 11, 12 and 13 show the surplus gas available from the Trunk-Line system if this surplus is scheduled to suit the requirements of Western Pipe Lines as projected by Mr. Hawthorn. It may be seen that the 30 year requirements of both the Province and Western Pipe Lines may be met with ease.

Conclusion

The Board concludes that integrated gathering facilities based upon a Provincially controlled Trunk-Line system operating as a common carrier would facilitate conservation, provide for flexibility of development, give maximum protection to the Province and be in the mutual interest of consumers, producers and transporters of natural gas. Such a system would allow dry gas fields better to share in the higher load factors of an export market as well as permitting higher load factors for wet gas fields and their associated plants. An integrated plan based on the Trunk-Line system could deliver gas at the eastern border of the Province in quantities and at rates which, for all practical purposes, would meet the requirements of either Trans-Canada Pipe Lines Limited, et al, or Western Pipe Lines.

Table F-1

The Petroleum and Natural Gas Conservation Board

COMPOSITE ALBERTA REQUIREMENTS FOR INTEGRATED SYSTEM

1	2	3	4	5	6	7	8	9	10	11	12	13
	Canadian W. Natural Gas Co.			Northwestern Utilities Ltd.			Local (@ ⅓ Total* Local Requirements)			Total Requirements		
Year	Annual B.C.F.	Peak MMCFD.	Load Factor Percent	Annual B.C.F.	Peak MMCFD.	Load Factor Percent	Annual B.C.F.	Peak MMCFD.	Load Factor Percent	Annual B.C.F.	Peak MMCFD.	Load Factor Percent
1953	27.8	181	42	31.0	189	45	0.9	6	40	59.7	376	43.5
1954	30.0	196	42	43.6	249	48	1.7	12	40	75.3	457	45.2
1955	31.6	206	42	50.0	285	48	2.1	14	40	83.7	505	45.5
1956	33.0	215	42	55.6	311	49	2.3	16	40	90.9	542	46.0
1957	34.8	227	42	61.1	335	50	2.5	17	40	98.4	579	46.5
1958	36.4	237	42	64.0	351	50	2.7	19	40	103.1	607	46.5
1959	37.8	247	42	67.0	367	50	3.1	21	40	107.9	635	46.5
1960	39.6	258	42	70.2	385	50	3.3	23	40	113.1	666	46.5
1961	40.7	265	42	71.4	391	50	3.4	23	40	115.5	679	46.5
1962	41.3	269	42	72.7	398	50	3.5	24	40	117.5	691	46.5
1963	42.0	274	42	74.2	407	50	3.7	25	40	119.9	706	46.5
1964	42.8	279	42	75.5	414	50	3.8	26	40	122.1	719	46.5
1965	43.7	285	42	76.8	421	50	3.9	27	40	124.4	733	46.5
1966	44.5	290	42	78.3	429	50	4.0	27	40	126.8	746	46.5
1967	45.4	296	42	79.8	437	50	4.1	28	40	129.3	761	46.5
1968	46.4	303	42	81.2	445	50	4.2	29	40	131.8	777	46.5
1969	47.3	309	42	82.8	454	50	4.3	29	40	134.4	792	46.5
1970	48.3	315	42	84.2	461	50	4.4	30	40	136.9	806	46.5
1971	48.9	319	42	85.4	468	50	4.5	31	40	138.8	818	46.5
1972	49.6	324	42	86.6	475	50	4.6	31	40	140.8	830	46.5
1973	50.4	329	42	87.8	481	50	4.7	32	40	142.9	842	46.5
1974	51.1	333	42	89.1	488	50	4.8	33	40	145.0	854	46.5
1975	51.8	338	42	90.4	495	50	4.9	34	40	147.1	867	46.5
1976	52.7	344	42	91.6	502	50	5.0	34	40	149.3	880	46.5
1977	53.4	348	42	92.9	509	50	5.1	35	40	151.4	892	46.5
1978	54.3	354	42	94.1	516	50	5.2	36	40	153.6	906	46.5
1979	55.1	359	42	95.6	524	50	5.3	36	40	156.0	919	46.5
1980	55.8	364	42	96.9	531	50	5.4	37	40	158.1	932	46.5
1981	56.7	370	42	98.2	538	50	5.6	38	40	160.5	946	46.5
1982	57.5	375	42	99.7	546	50	5.6	38	40	162.8	959	46.5
Total	1350.7			2327.7			118.6			3979.0		

* Exclusive of Peace River Area and Medicine Hat-Redcliffe

APPENDIX F

Table F-2

The Petroleum and Natural Gas Conservation Board

ILLUSTRATIVE DELIVERABILITY SCHEDULE FOR THE REQUIREMENTS OF NORTHWESTERN UTILITIES LIMITED, CANADIAN NATURAL GAS COMPANY LIMITED, & 1/3 LOCAL, FOR AN INTEGRATED SYSTEM

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32
	Total Requirements *			Total Oil Field Gas			Turner Valley			Jumping Pound			Foremost				Okotoks			Olds			Homeglen Composite Nevis			Homeglen - Rimbey			Residual Requirements		
Year	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent	Bow Island Peak MMCFD	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent
1953	59.7	376	43.5	8.2	21.4	105.0	19.7	95	56.8	7.9	31.0	70	0.2	14.0	3.9	41.0													23.7	173.6	37.3
1954	75.3	457	45.2	8.8	25.8	105.0	18.0	95	51.8	11.8	46.0	70	0.2	13.9	3.9	41.1													36.5	235.2	42.5
1955	83.7	505	45.5	23.6	58.2	111.1	17.1	95	49.3	14.3	56.0	70	0.2	13.8	4.0	41.2													28.5	240.8	32.2
1956	90.9	542	46.0	37.5	93.7	109.7	17.5	95	50.4	17.5	60.0	80	0.2	13.7	4.0	41.3							8.4	28.8	80	2.8	6.9	111	7.0	202.6	9.5
1957	98.4	579	46.5	44.7	111.5	109.9	17.7	95	51.0	17.5	60.0	80	0.2	13.6	4.0	41.4	3.3	11.2	80	1.4	5.0	80	8.4	28.8	80	2.8	6.9	111	-2.4	205.6	3.2
1958	103.1	607	46.5	45.8	114.1	110.0	17.7	95	51.0	17.5	60.0	80	0.2	13.6	4.0	41.4	3.3	11.2	80	1.4	5.0	80	16.8	57.6	80	2.8	6.9	111	-2.4	202.2	—
1959	107.9	635	46.5	46.0	114.7	110.0	15.6	84	51.0	17.5	60.0	80	0.2	13.5	4.1	41.5	3.3	11.2	80	1.4	5.0	80	16.8	57.6	80	2.8	6.9	111	4.3	240.6	4.9
1960	113.1	666	46.5	46.2	115.1	110.0	15.6	84	51.0	17.5	60.0	80	0.2	13.4	4.1	41.6	3.3	11.2	80	1.4	5.0	80	16.8	57.6	80	2.8	6.9	111	9.3	271 2	9.4
1961	115.5	679	46.5	46.3	115.4	110.0	15.3	82	51.0	17.3	59.2	80	0.2	13.3	4.1	41.7	3.3	11.2	80	1.4	5.0	80	16.8	57.6	80	2.8	6.9	111	12.1	286.7	11.5
1962	117.5	691	46.5	44.2	110.3	110.0	15.3	82	51.0	16.4	56.2	80	0.2	13.2	4.1	41.8	3.3	11.2	80	1.4	5.0	80	16.8	57.6	80	2.8	6.9	111	17.1	306.8	15.3
1963	119.9	706	46.5	43.9	109.9	109.4	15.3	82	51.0	15.1	51.7	80	0.2	13.1	4.2	41.9	3.3	11.2	80	1.4	5.0	80	16.8	57.6	80	5.6	13.8	111	18.3	319.8	15.7
1964	122.1	719	46.5	43.5	108.7	109.9	15.3	82	51.0	14.2	48.6	80	0.2	13 0	4.2	42.0	3.1	10.7	80	1.4	5.0	80	16.8	57.6	80	5.6	13.8	111	22.0	337.6	17.8
1965	124.4	733	46.5	42.3	105.9	109.5	15.3	82	51.0	13.3	45.6	80	0.2	12.9	4.2	42.1	3.1	10.7	80	1.4	5.0	80	16.8	57.6	80	5.6	13.8	111	26.4	357 4	20.2
1966	126.8	746	46.5	41.8	104.6	109.6	15.3	82	51.0	12.4	42.5	80	0.2	12.9	4.3	42.1	2.9	9.9	80	1.4	5.0	80	16.8	57.6	80	11.2	38.4	80	24.8	351 0	19.3
1967	129.3	761	46.5	41.9	104.7	109.7	15.3	82	51.0	11.6	39.8	80	0.2	12.8	4.3	42.2	2.8	9.6	80	1.3	4.5	80	16.1	55.0	80	11.2	38.4	80	28.9	372.0	21.3
1968	131.8	777	46.5	32.3	87.0	101.8	14.8	79	51.0	10.9	37.5	80	0.2	12.7	4.3	42.3	2.7	9.3	80	1.3	4.5	80	14.9	51.0	80	16.8	57.6	80	37.9	396.1	26.2
1969	134.4	792	46.5	30.5	80.6	103.7	13.2	71	51.0	10.2	35.0	80	0.2	12.6	4.3	42.4	2.6	8.9	80	1.2	4.1	80	13.9	47.5	80	16.8	57.6	80	45.8	432.3	29.0
1970	136.9	806	46.5	28.5	74.1	105.3	12.1	65	51.0	9.6	32.9	80	0.2	12.5	4.4	42.5	2.5	8.6	80	1.2	4.1	80	12.8	44.0	80	16.8	57.6	80	53.2	464.7	31.4
1971	138.8	818	46.5	25.3	64.9	106.9	10.8	58	51.0	9.0	30.8	80	0.2	12.4	4.4	42.6	2.4	8.2	80	1.1	3.8	80	12.0	41.1	80	28.0	96.0	80	50.0	460.2	29.7
1972	140.8	830	46.5	24.2	61.3	108.2	10.1	54	51.0	8.4	28.8	80	0.2	12.3	4.4	42.7	2.3	7.9	80	1.1	3.8	80	11.2	38.3	80	28.0	96.0	80	55.3	484.9	31.3
1973	142.9	842	46.5	21.0	51.8	111.2	9.3	50	51.0	7.9	27.0	80	0.2	12.2	4.5	42.8	2.2	7.6	80	1.0	3.4	80	10.3	35.1	80	28.0	96.0	80	63.0	516.1	33.4
1974	145.0	854	46.5	20.2	49.2	112.5	6.9	37	51.0	7.4	25.3	80	0.2	12.1	4.5	42.9	2.1	7.2	80	0.9	3.1	80	9.5	32.5	80	28.0	96.0	80	69.8	548.7	34.9
1975	147.1	867	46.5	20.4	66.5	84.1	5.6	30	51.0	6.9	24.6	80	0.2	12.1	4.5	42.9	2.1	7.2	80	0.9	3.1	80	8.9	30.5	80	28.0	96.0	80	74.1	554.1	36.6
1976	149.3	880	46.5	27.1	89.5	83.0	4.8	26	51.0	6.5	22.2	80	0.2	12.0	4.5	43.0	2.0	6.8	80	0.8	2.7	80	8.2	28.1	80	28.0	96.0	80	71.7	553.7	35.5
1977	151.4	892	46.5	38.3	128.2	81.9	4.3	23	51.0	6.1	20.9	80	0.2	11.9	4.6	43.1	1.9	6.5	80	0.8	2.7	80	7.6	26.2	80	28.0	96.0	80	64.2	533.5	33.0
1978	153.6	906	46.5	38.1	127.6	81.8	3.9	21	51.0	5.8	19.8	80	0.2	11.8	4.6	43.2	1.8	6.2	80	0.8	2.7	80	7.0	24.0	80	28.0	96.0	80	68.0	553.7	33.6
1979	156.0	919	46.5	36.5	123.9	80.7	3.4	18	51.0	5.4	18.5	80	0.2	11.7	4.7	43.3	1.8	6.2	80	0.7	2.4	80	6.6	22.6	80	24.8	89.0	80	76.6	583.4	36.0
1980	158.1	932	46.5	35.0	120.0	80.0	2.8	15	51.0	5.0	17.1	80	0.2	11.6	4.7	43.4	1.7	5.8	80	0.7	2.4	80	6.1	20.9	80	22.8	78.0	80	83.8	617.8	37.2
1981	160.5	946	46.5	35.0	120.0	80.0	2.4	13	51.0	4.7	16.1	80	0.2	11.5	4.8	43.5	1.6	5.5	80	0.7	2.4	80	5.6	19.2	80	19.6	67.0	80	90.7	647.8	38.4
1982	162.8	959	46.5	35.0	120.0	80.0	2.2	12	51.0	4.4	15.1	80	0.2	11.4	4.8	43.6	1.6	5 5	80	0.6	2.1	80	5.2	17.8	80	17.2	59.0	80	96.4	672.5	39.3
Total	3797.0			1012.1			352.6			330.0			6.0				66.3			29.1			323.9			417.6			1259.4		
Waste Prior to Plant Completion				28.2																						3.0					
Established Reserves Available for Disposition				1469.5			370.0			375.0			21.0			16.0	100.0			40.0			390.0			500.0					
Percentage Withdrawn				70.8			95.3			88.0			29.0			0	66.3			72.8			83.0			84.1					

* From Table F-1

Table F-3

The Petroleum and Natural Gas Conservation Board

ILLUSTRATIVE DELIVERABILITY SCHEDULE TO MEET THE REQUIREMENTS OF TRANS-CANADA PIPELINES LIMITED

1	2	3	4	5	6	7	8	9	10	11	12	13
	Residual Requirements*			Pincher Creek			Dry Gas Fields and Deferred Oil Field Gas			Surplus Available Gas**		
Year	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent
1953	23.7	173.6	37.3				23.7	173.6	37.5			
1954	36.5	235.2	42.5				36.5	235.2	42.5			
1955	28.5	240.8	32.2				43.1	300.8	39.3	14.6	60.0	66.7
1956	7.0	202.6	9.5	32.4	111.0	80	75.0	391.6	52.5	100.4	300.0	91.7
1957	2.4	205.6	3.2	40.9	140.0	80	69.2	400.6	47.3	107.7	335.0	88.2
1958	—2.4	202.2	—	49.6	170.0	80	63.0	397.2	43.9	115.0	365.0	86.2
1959	4.3	240.6	4.9	58.4	200.0	80	70.0	480.6	39.9	124.1	440.0	77.2
1960	9.3	271.2	9.4	58.4	200.0	80	84.1	571.2	40.4	133.2	500.0	73.0
1961	12.1	286.7	11.5	58.4	200.0	80	86.9	451.7	52.6	133.2	365.0	100.0
1962	17.1	306.8	15.3	58.4	200.0	80	91.9	471.8	53.3	133.2	365.0	100.0
1963	18.3	319.8	15.7	58.4	200.0	80	93.1	484.8	52.7	133.2	365.0	100.0
1964	22.0	337.6	17.8	58.4	200.0	80	96.8	502.6	52.8	133.2	365.0	100.0
1965	26.4	357.4	20.2	58.4	200.0	80	101.2	522.4	53.0	133.2	365.0	100.0
1966	24.8	351.0	19.3	58.4	200.0	80	99.6	516.0	52.9	133.2	365.0	100.0
1967	28.9	372.0	21.3	58.4	200.0	80	103.7	537.0	52.9	133.2	365.0	100.0
1968	37.9	396.1	26.2	58.4	200.0	80	112.7	561.1	55.0	133.2	365.0	100.0
1969	45.8	432.3	29.0	58.4	200.0	80	120.6	597.3	55.3	133.2	365.0	100.0
1970	53.2	464.7	31.4	58.4	200.0	80	128.0	629.7	55.8	133.2	365.0	100.0
1971	50.0	460.2	29.7	57.2	196.0	80	126.0	629.2	55.0	133.2	365.0	100.0
1972	55.3	484.9	31.3	54.6	187.0	80	133.9	662.9	55.4	133.2	365.0	100.0
1973	63.0	516.1	33.4	52.0	178.0	80	144.2	703.1	56.3	133.2	365.0	100.0
1974	69.8	548.7	34.9	49.6	170.0	80	153.4	743.7	56.6	133.2	365.0	100.0
1975	74.1	554.1	36.6	47.3	162.0	80	160.0	757.1	57.9	133.2	365.0	100.0
1976	71.7	553.7	35.5	45.6	156.0	80	159.3	762.7	57.3	133.2	365.0	100.0
1977	64.2	533.5	33.0	43.2	148.0	80	154.2	750.5	56.3	133.2	365.0	100.0
1978	68.0	553.7	33.6	41.5	142.0	80	139.0	720.0	52.9	112.5	308.3	100.0
1979	76.6	583.4	36.0	39.7	136.0	80	114.5	660.0	47.5	77.6	212.6	100.0
1980	83.8	617.8	37.2	37.7	129.0	80	46.1	488.8	26.7	0	0	0
1981	90.7	647.8	38.4	35.9	123.0	80	54.8	524.8	28.6			
1982	96.4	672.5	39.3	34.5	118.0	80	61.9	554.5	30.6			
Total	1259.4			1362.5			2946.4			3049.5		
Established Reserves Available for Disposition				2000.0			3399.8					
Percentage Withdrawn				68.1			86.7					

*From Table F-2

** Scheduled to suit Trans-Canada Pipelines Ltd. Requirements

APPENDIX F

Table F-4

The Petroleum and Natural Gas Conservation Board

ILLUSTRATIVE DELIVERABILITY SCHEDULE TO MEET THE REQUIREMENTS OF WESTERN PIPELINES

1	2	3	4	5	6	7	8	9	10	11	12	13
	Residual Requirements*			Pincher Creek			Dry Gas and Deferred Gas Composite			Surplus Available Gas**		
Year	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent	Annual B.C.F.	Peak MMCFD.	Load Factor Per Cent
1953	23.7	173.6	37.3				23.7	173.6	37.3			
1954	36.5	235.2	42.5				36.5	235.2	42.5			
1955	28.5	240.8	32.2				79.5	421.8	51.6	51.0	181.0	77.2
1956	7.0	202.6	9.5	29.2	100	80	41.9	300.6	38.2	64.1	198.0	77.0
1957	2.4	205.6	3.2	38.0	130	80	31.4	289.6	29.7	67.0	214.0	89.0
1958	-2.4	202.2	-	40.9	140	80	26.1	289.2	24.7	69.4	227.0	86.0
1959	4.3	240.6	4.9	43.8	150	80	31.9	329.6	26.5	71.4	239.0	82.0
1960	9.3	271.2	9.4	43.8	150	80	36.9	360.2	28.0	71.4	239.0	82.0
1961	12.1	286.7	11.5	43.8	150	80	39.7	375.7	29.1	71.4	239.0	82.0
1962	17.1	306.8	15.3	43.8	150	80	44.7	395.8	31.0	71.4	239.0	82.0
1963	18.3	319.8	15.7	43.8	150	80	45.9	408.8	30.8	71.4	239.0	82.0
1964	22.0	337.6	17.8	43.8	150	80	49.6	426.6	31.9	71.4	239.0	82.0
1965	26.4	357.4	20.2	43.8	150	80	54.0	446.4	33.2	71.4	239.0	82.0
1966	24.8	351.0	19.3	43.8	150	80	52.4	440.0	32.6	71.4	239.0	82.0
1967	28.9	372.0	21.3	43.8	150	80	56.5	461.0	33.6	71.4	239.0	82.0
1968	37.9	396.1	26.2	43.8	150	80	65.5	485.1	37.1	71.4	239.0	82.0
1969	45.8	432.3	29.0	43.8	150	80	73.4	521.3	38.5	71.4	239.0	82.0
1970	53.2	464.7	31.4	43.8	150	80	80.8	553.7	40.0	71.4	239.0	82.0
1971	50.0	460.2	29.7	43.8	150	80	77.6	549.2	38.7	71.4	239.0	82.0
1972	55.3	484.9	31.3	43.8	150	80	82.9	573.9	39.6	71.4	239.0	82.0
1973	63.0	516.1	33.4	43.8	150	80	90.6	605.1	41.0	71.4	239.0	82.0
1974	69.8	548.7	34.9	43.8	150	80	97.4	637.7	41.9	71.4	239.0	82.0
1975	74.1	554.1	36.6	43.8	150	80	101.7	643.1	43.2	71.4	239.0	82.0
1976	71.7	553.7	35.5	43.8	150	80	99.3	642.7	42.3	71.4	239.0	82.0
1977	64.2	533.5	33.0	43.8	150	80	91.8	622.5	40.1	71.4	239.0	82.0
1978	68.0	553.7	33.6	43.8	150	80	95.6	642.7	40.7	71.4	239.0	82.0
1979	76.6	583.4	36.0	43.8	150	80	104.2	672.4	42.4	71.4	239.0	82.0
1980	83.8	617.8	37.2	43.8	150	80	111.4	706.8	43.1	71.4	239.0	82.0
1981	90.7	647.8	38.4	43.8	150	80	118.3	736.8	44.0	71.4	239.0	82.0
1882	96.4	672.5	39.3	43.8	150	80	124.0	761.5	44.7	71.4	239.0	82.0
Total	1259.4			1159.3			2065.2			1965.1		
Established Reserves Available for Disposition				2000.0			3399.8					
Percentage Withdrawn				58.0			60.7					

*From Table F-2

**Scheduled to suit Western Pipeline's Requirements.

Table F-5

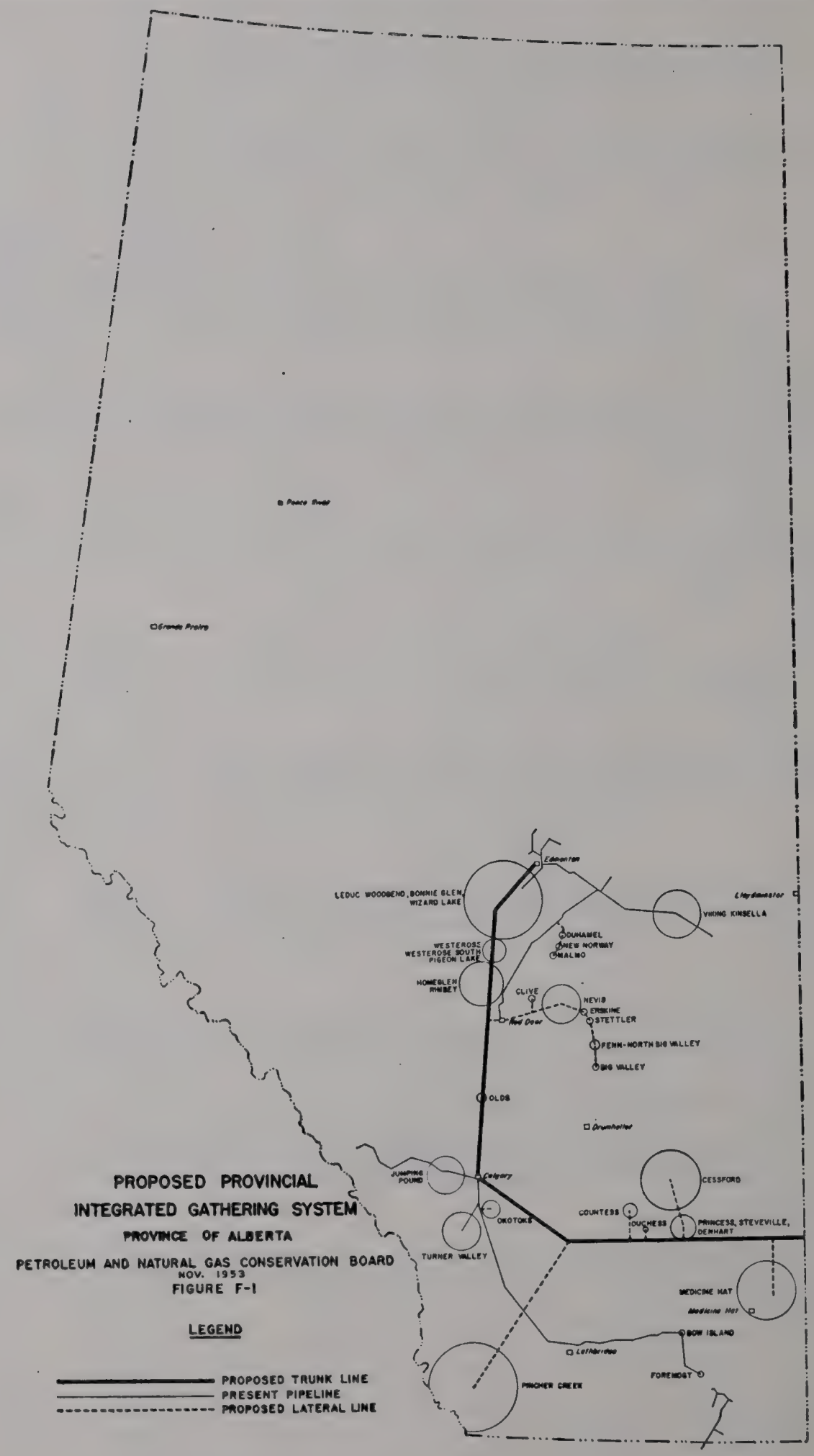
The Petroleum and Natural Gas Conservation Board

BASIC DELIVERABILITY DATA FOR FIELDS OF TABLES F-3 AND F-4

1	2	3	4	5
Name of Field	Zone	Present No. of Wells	Estimated No. of Wells (Field Fully Developed)	Absolute Open Flow Per Well Disposable Gas MMCFD
Viking Kinsella	Viking	100	150	92.0
Edmonton Dry Gas Composite (See Table D-4)		63	152	12.8
Cessford Composite Unassociated (See Table D-4)		30	145	5.3
Medicine Hat Residual	Medicine Hat S.S.	10	50	2.7
Small Gas Fields				
Alix	Lower Cretaceous	1	1	9.5
Bashaw	Leduc			1.3*
Big Valley	Viking and Nisku			1.8*
Big Valley N. and Fenn	Viking and Nisku			6.4*
Chigwell	Basal Blairmore	1	1	13.3
Clive	Viking, Basal Blairmore and Devonian	0	2	1.9 1.7*
Erskine	Lower Cretaecous and Leduc			1.8*
Stettler	Nisku			3.3*
Wildunn Creek	Viking	1	2	6.6
Other Small Fields		7	10	5.7
Total Small Gas Fields		10	20**	5.0
Total Viking, Kinsella, Medicine Hat Residual, Edmonton Dry Gas Composite, Cessford Composite Unassociated, and Small Gas Fields		213	517	7.7
Cessford Composite Assoc. (See Table D-4)		16	140	7.1
Edmonton Deferred Gas (See Table D-4)		2	86	22.2
Westerose Deferred Composite (See Table D-4)		3	20	17.8

*Estimated Average Daily Gas Available from Possible Plants.

**Includes six possible processing plants.


Peace River
Grande Prairie
Edmonton
LEDUC WOODBEND, BONNIE GLEN, WIZARD LAKE
Lloydminster
VIKING KINSELLA
DUHAMEL
NEW NORWAY
MALMO
WESTEROSS
WESTEROSE SOUTH
PIGEON LAKE
HOMEGLEN
RIMBEY
CLIVE
NEVIS
ERSKINE
STETTLER
Red Deer
PENN-NORTH BIG VALLEY
BIG VALLEY
OLDS
Drumheller
JUMPING POUND
Calgary
CESSFORD
COUNTESS
DUCHESS
PRINCESS, STEVEVILLE, DENHART
OKOTOKS
TURNER VALLEY
MEDICINE HAT
Medicine Hat
BOW ISLAND
Lethbridge
FOREMOST
PINCHER CREEK
PROPOSED PROVINCIAL
INTEGRATED GATHERING SYSTEM
PROVINCE OF ALBERTA
PETROLEUM AND NATURAL GAS CONSERVATION BOARD
NOV. 1953
FIGURE F-1
LEGEND
PROPOSED TRUNK LINE
PRESENT PIPELINE
PROPOSED LATERAL LINE

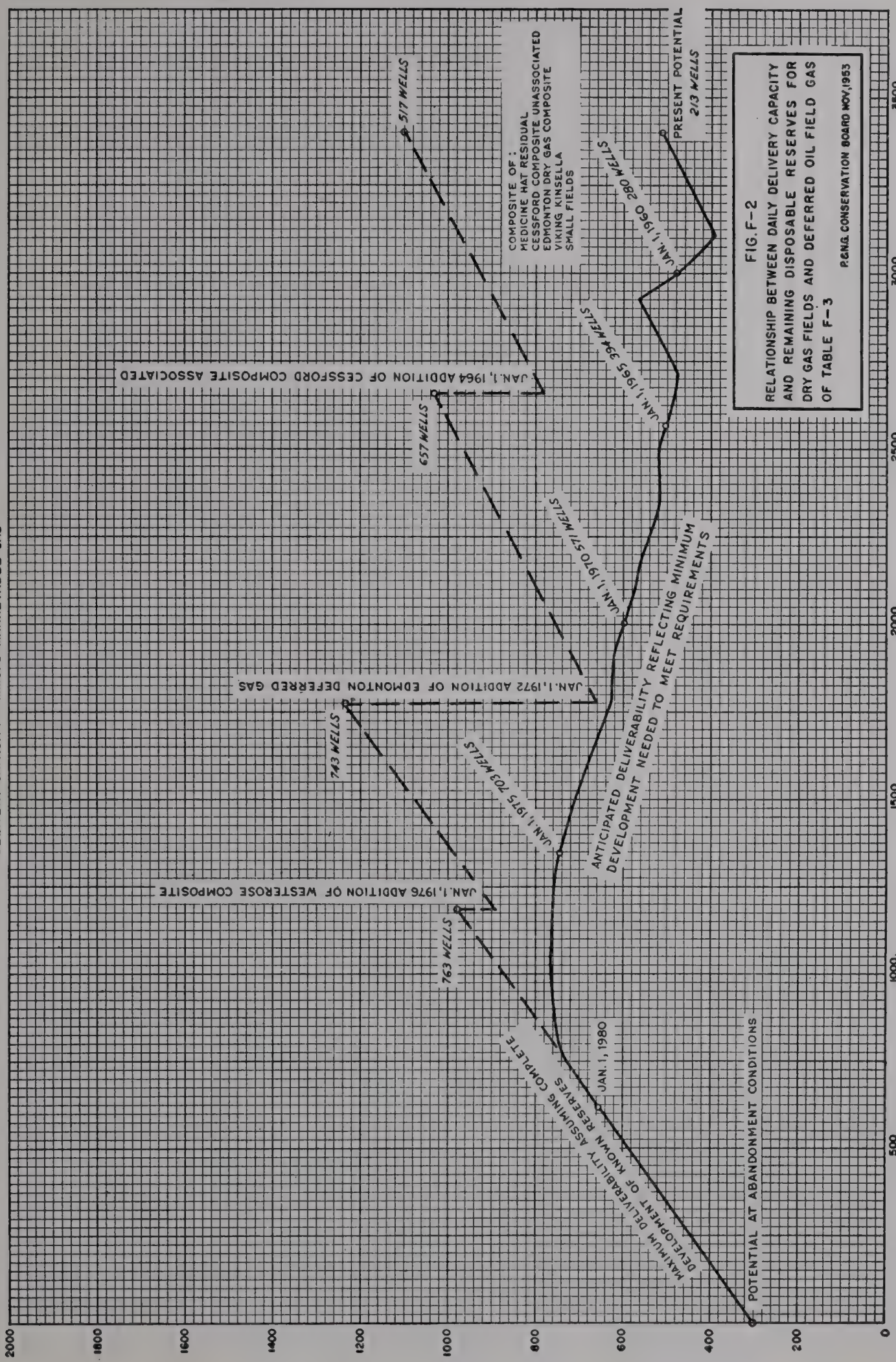


FIG. F-2

RELATIONSHIP BETWEEN DAILY DELIVERY CAPACITY AND REMAINING DISPOSABLE RESERVES FOR DRY GAS FIELDS AND DEFERRED OIL FIELD GAS OF TABLE F-3

P.&N.G. CONSERVATION BOARD NOV. 1953

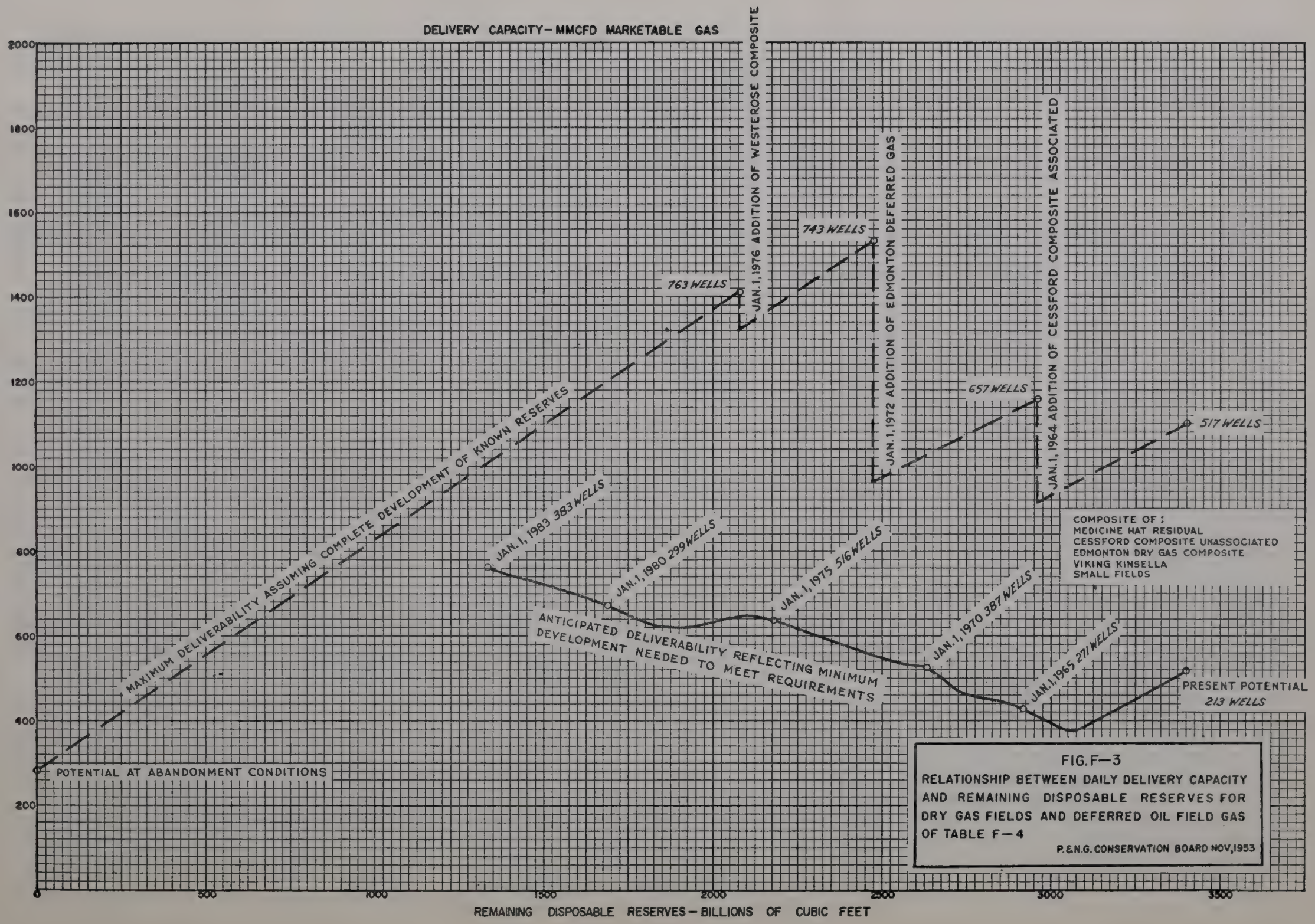


FIG. F—3

RELATIONSHIP BETWEEN DAILY DELIVERY CAPACITY AND REMAINING DISPOSABLE RESERVES FOR DRY GAS FIELDS AND DEFERRED OIL FIELD GAS OF TABLE F—4

P.E.N.G. CONSERVATION BOARD NOV, 1953

APPENDIX G

MARKETS OUTSIDE OF ALBERTA

Canadian-Montana Pipe Line Company

The applicant desires to remove from the Province of Alberta to the State of Montana all gas which may be produced in the Province from the Pakowki Lake area comprising the Black Butte, Pendant d'Oreille, Smith-Coulee and Manyberries fields. The applicant company is a wholly-owned subsidiary of the Montana Power Company. Most of the known reserves in the Pakowki Lake area are owned by the Canadian-Montana Gas Company, also a wholly-owned subsidiary of The Montana Power Company.

Mr. J. E. Corette, President of The Montana Power Company, gave evidence in regard to the company's market requirements. He pointed out that in his submission the requirements had not been extended beyond 1970 because even with Alberta gas the company would not have sufficient supply to satisfy its estimated demand from 1963 on. The Board is satisfied that even with the inclusion of the Etzikom reserves with those of other fields applied for that the Company would have no marketing difficulties.

The Board has no doubt that a market exists in Montana for the amount of gas which the applicant is asking permission to remove.

Trans-Canada Pipe Lines Limited, Trans-Canada Grid of Alberta Ltd. and Canadian Delhi Oil Ltd.

The applicants request permission to export or cause to be exported from the Province a maximum of 365 million cubic feet of gas per day for a period of 25 years to serve markets in the Province of Saskatchewan, Manitoba, Ontario and Quebec.

The applicants presented to the Board two separate studies of estimated sales in the marketing areas to be served. The estimate used in the preparation of submissions relative to the economic feasibility of the whole project was made by the H. K. Ferguson Company who retained Mr. Shattuck to do the work. The other estimate was prepared by Mr. Poor of Ford, Bacon & Davis Incorporated. Mr. Shattuck's estimate was based on the amount of gas covered by the application plus 50 million cubic feet per day from Saskatchewan and assumed that peak day requirements over and above the 415 million cubic feet per day would be met from gas storage fields close to the high consuming areas in the East.

Mr. Shattuck estimated gas requirements for the first 5 years in accordance with Table G-1 of this report. He estimated firm sales also in the tenth year would be 122 billion cubic feet with a peak day requirement of 800 million cubic feet.

On the basis of unlimited gas supply, Mr. Shattuck estimated all classes of sales could reach 200 billion cubic feet in the fifth year.

Mr. Poor in his estimate presumed that sufficient gas would be made available to operate the Trans-Canada system at full capacity with peak day sales of approximately 550 million cubic feet in the fifth year. Mr. Poor's estimated sales for the first five years are also shown on Table G-1.

The evidence of both Messrs. Shattuck and Poor was to the effect that the applicants could market considerably more gas than the amount applied for. Mr. Poor's estimate for first year sales was 8.6 per cent greater than Mr. Shattuck's and his fifth year was 20.4 per cent higher. There was also a difference of opinion between them with respect to their estimates of the various loads (residential, commercial, industrial firm and industrial interruptible) and the prices at which these loads could be sold for. Mr. Poor's estimated firm sales for the first and fifth years were 20.7 per cent and 17.8 per cent higher than Mr. Shattuck's for the corresponding years.

Western Pipe Lines, through Mr. Ritchie of Stone & Webster Service Corporation, submitted market studies for the same areas as Trans-Canada Pipe Lines Limited, et al, relative to Phase I and Phase II of their project. These estimates are presented in Table G-11 and discussed in some detail later on. Mr. Ritchie's estimates for the Eastern Canadian market were appreciably lower than those of Messrs. Shattuck and Poor even though they were premised on:

(a) lower retail selling prices; and

(b) gas from Western Canada being made available some four or five years later than Trans-Canada Pipe Lines Limited, et al, proposed in order to permit the Ontario market to be built up in the meantime from the existing reserves in the Province together with gas imported from the United States.

The Honourable Mr. Kelly, Minister of Mines of the Province of Ontario, and Mr. A. F. Crozier, Fuel Controller, presented a submission on behalf of their Government. The submission outlined Ontario's fuel position as follows:

(a) there was an increasing demand for all types of fuels;

(b) there were no commercial deposits of coal in the Province and very limited reserves of oil and gas;

(c) companies distributing manufactured gas faced an uncertainty of supply and higher costs of fuels from which to produce gas;

(d) the Province must seek an economic supply of natural gas to meet their fuel requirements; and

(e) four reports prepared by companies interested in supplying gas from Alberta and Saskatchewan to Eastern Canada indicated it was possible to pipe the gas to Eastern Canada and sell it at a price competitive with other fuels.

The Government of Ontario went on record as being in favour of development and use of Canada's resources primarily for the benefit of Canadians and petitioned the Board to give every possible consideration to the pressing and ever growing need for large volumes of natural gas in Eastern Canada.

Prior to the August adjournment the following Canadian distributors presented submissions to the Board with respect to the areas they now serve or propose to serve:

(a) The Greater Winnipeg Gas Company;

(b) The Union Gas Company of Canada Limited; and

(c) The Consumer's Gas Company of Toronto.

After hearing the market evidence to the time of the adjournment, it was evident to the Board that there was a significant difference of opinion between the various estimators as to:

(a) retail prices which the various loads could be sold for;

(b) volumes of the various loads which could be marketed; (N.B. The differences in estimated volumes were not necessarily reflected by the retail selling price assumed.)

(c) the amount of spread; i.e., the difference between the purchase price and average retail selling price per MCF of gas which the distributor would require to make gas available to the ultimate consumer; and

(d) the gate price which the distributor could afford to pay. In addition it was evident that while the distributors expressed a desire to get Alberta gas they would not commit themselves as to volume or price.

In an effort to clarify the situation with respect to the various market estimates, the Board made the following statement prior to adjourning the hearings for three weeks in August of this year:

> "It appears to the Board as though it will be able to declare the existence of a fairly substantial amount of gas surplus to the present and future needs of the people of the Province. How much the surplus will be and where it will be located cannot be indicated at the present time.
>
> "The Board is appreciative of the evidence on markets outside Alberta brought forth by the applicants as well as that freely offered by others interested in the supply of surplus Alberta gas to such markets. While the Board realizes that expert witnesses may honestly differ in their opinions, nevertheless, we feel that an effort should be made to place before us clearer evidence with respect to available markets and their rates of growth. The Board is hopeful that the applicants may be able to have the proposed distributing companies, especially those in the main Canadian market areas East of Alberta, state their positions more clearly and indicate what volumes of Alberta gas they are prepared to contract for and at what prices.
>
> "We are prepared to hear further evidence on these matters when the sittings resume on August 24th."

Following the resumption of the hearings, the Counsel for Trans-Canada Pipe Lines Limited, et al, stated that they had interviewed a number of distributors but were unable to secure contracts as the distributors were not willing to reveal their bargaining position in view of the uncertainty of the coming of gas to their areas.

The Board received several letters from Ontario distributors following interviews with officials of Trans-Canada Pipe Lines Limited, et al, expressing their desire to obtain Alberta gas and in some cases indicating the amounts they would take and the approximate price they were prepared to pay. However, these letters did not represent a sufficient per cent of estimated sales on which the Board could safely assess the sales potential in Eastern Canada.

The difficulties faced by the Board in determining the competitive market for gas in Eastern Canada without stronger supporting evidence from the distributors as to the amount of gas they would be prepared to take probably can be illustrated by a discussion of the Montreal area which would be served by the Quebec Hydro-Electric Commission. Furthermore, the Montreal area represents 33.5 per cent and 33.8 per cent respectively, of Trans-Canada Pipe Lines Limited, et al, first and fifth year total sales as estimated by Mr. Shattuck.

This area is selected for comparison because more evidence was received relating to its market potential than in the case of any other area.

Table G-3 shows a comparison of the estimates for the Montreal area made by Messrs. Ritchie, Poor and Shattuck for the first and fifth years in which natural gas would be available in Montreal as proposed by Western Pipe Lines and Trans-Canada Pipe Lines Limited, et al.

It will be noted that the biggest discrepancies in the total natural gas requirements and for the individual sale categories occur in the first year and that by the fifth year the estimates of Messrs. Ritchie and Shattuck for total gas requirements are fairly close to indicating a difference of opinion in regard to the rate of attachment of the load.

Mr. Poor's estimated firm requirements in the fifth year are 16 per cent higher than Mr. Shattuck's and Mr. Ritchie's in turn are 20 per cent lower than Mr. Shattuck's. Mr. Poor's total requirements for the fifth year, including interruptible, are 31 per cent higher than Mr. Shattuck's and Mr. Ritchie's 6 per cent lower than Mr. Shattuck's.

There was quite a wide difference of opinion between the estimators as to what prices the various loads (residential, commercial, etc.) could be sold for. This was most apparent in prices assumed for residential sales. Mr. Shattuck assumed a base load (cooking etc.) price of $1.65 per MCF and a space heating of $1.50 per MCF. Mr. Shattuck claimed residential consumers would pay 1.4 times the price of competitive fuels based on experience in the United States. Mr. Ritchie stated gas would have to compete with prices paid for competitive fuels now in use which on an equivalent MCF (1000 B.t.u.) range from $1.01 to $1.07. Mr. Poor used a residential rate of $1.10.

It is interesting to note that Mr. Shattuck's estimate of residential sales in the fifth year is the largest even though he assumed the highest retail selling price. His estimate of sales is slightly higher than Mr. Ritchie's and 35 per cent higher than Mr. Poor's who admitted on cross-examination that if he had assumed Mr. Shattuck's prices, he could not have developed the residential space heating saturation he had estimated.

There was also quite a difference of opinion as to the spread the distributors would require to finance their operations.

The Quebec Hydro-Electric Commission presented its submission to the Board, after the August adjournment, through Mr. Latreille, one of the Commissioners and Manager of the Gas Division, and Mr. T. Cross, Chief Engineer.

The position of the Quebec Hydro-Electric Commission as outlined by Mr. Latreille may be summed up as follows:

(1) The Commission, despite the fact its main business was distribution of electric power, would aggressively push the sale of natural gas because of the rapidly increasing demand for electric power coupled with the decreasing accessibility of large power sites.

(2) The limiting factor in pushing sales of manufactured gas which it now distributes was the ever increasing cost of production and distribution.

(3) There were three vital factors which must be established before the Commission would contract to buy natural gas:

(a) An assured dependable and adequate supply of gas over a long enough period to justify the investment;

(b) A price that would enable them to secure sufficient business to warrant the investment; and

(c) Provisions in the rate structure that would enable them to build their load during the first few years of natural gas operations without severe penalties.

N.B. The submission indicated no firm proposal incorporating these conditions had been offered to the Commission.

Mr. Latreille stated the Commission had retained the firm of Ford, Bacon & Davis, Incorporated to prepare a market study which was completed in June, 1952. In addition six other studies had been made that he knew of including those of Messrs. Poor, Shattuck and Ritchie. The Commission had co-operated in the making of these studies when its assistance had been requested. An exhibit was filed by the Commission at the hearing showing in graph form the estimated firm sales and firm plus interruptible sales for the first five years of natural gas service in Montreal as indicated in six of the studies.

These studies show a range in firm annual sales for the first year, following the introduction of natural gas, of from 17 to 31 BCF and for the fifth year the range is

between 14.7 and 37 BCF. Firm and interruptible sales in the first year range between 6.7 and 32 BCF and for the fifth year between 33.1 and 51.3 BCF.

Mr. Latreille commented on "the surprising difference of opinion" shown in the various reports and that he readily understood the Board's request for information from those most directly concerned—the distributors.

Mr. Latreille also informed the Board that the Commission had a study under way to determine:

(a) the cost of making natural gas available to their customers;

(b) the price the Commission could afford to pay for gas; and

(c) the rates the Commission would have to charge to make it a sound financial undertaking.

He indicated the study would be completed about December 1st, 1953 and that the Commission would be glad to present the conclusions reached. Lacking this information the Commission could only express the opinion that the potential market lay somewhere in the range of the various estimates.

Storage Facilities

As mentioned previously, Mr. Shattuck's market study assumed the use of storage facilities in Eastern Canada. Trans-Canada's project in fact depends on satisfactory arrangements being made for adequate storage facilities for peaking purposes.

The only evidence adduced by Trans-Canada Pipe Lines Limited, et al, with respect to storage was given by Mr. Schultz, Vice-President of Trans-Canada, who stated:

> "We recognized from the inception of this Trans-Canada pipe-line that a pipeline of this length needed at the far end adequate storage. There are several factors involved: No. 1, in case of line breaks, if you have storage you can continue in your deliveries to your customers; another point, you take care of peak loads in the winter time; No. 3, you are able to transmit it at high load factor, but by far the most important point is, in our talks with the Ontario Government and with Union, we have worked out a program whereby the Ontario Government will release control of this gas in Southern Ontario in the presently known fields to let this storage company have it for the purposes, two-fold purposes, of building a load in the Toronto-Hamilton area and to create a vacancy in the gas fields for the storing of Alberta gas to meet the peaks. Now, this is a very important point as far as we are concerned because it gives us at least a year and a half start on developing that Toronto-Hamilton market."

Mr. Schultz in reply to a question by Counsel for Western Pipe Lines stated that his discussions with Colonel Weir of the Union Gas Company of Canada Limited relative to the use of storage facilities by Trans-Canada had taken place prior to the three week adjournment in August and prior to Colonel Weir's appearance before the Board.

No attempt was made by Counsel for Trans-Canada to have Colonel Weir confirm the possibility of Trans-Canada making a deal with Union Gas Company for the use of their storage facilities.

No evidence was presented by Trans-Canada as to the ability of the gas fields controlled by Union Gas Company or Imperial Oil Limited to provide the peak loads required by them over and above Union Gas Company's own requirements. Mr. Crozier of the Ontario Government and Colonel Weir did give some evidence at the hearings in regard to the potential storage capacity of the gas fields in Southern Ontario but no technical data was supplied as to the deliverability characteristics of these fields.

While the Board does not doubt that Messrs. Shattuck and Poor are experts in their field and that their estimates were based on their own best judgment, it is not convinced, having regard to all of the evidence with respect to the markets involved, that the applicants have substantiated their case that the amount of gas applied for could be marketed and sold at a price which would enable the proposed gas transmission system to be built and operated and at the same time pay a fair price to the producers.

The Board is also of the opinion that Trans-Canada has not presented sufficient evidence to indicate its ability to meet peak demands by the use of storage not only for the first five years of operation but for subsequent years when the firm demand is being built up.

WESTERN PIPE LINES

Application

Western Pipe Lines are applying for permission to export a maximum of 275 MMCF of gas per day for 30 years (Phase I). Western Pipe Lines also propose to "apply hereafter, when adequate reserves and deliverabilities therefore have become established, for permission to export an additional 275 million cubic feet per day to make provision for deliveries of natural gas to supply markets in Eastern Canada." (Phase II).

Requirements

As mentioned in the discussion of Trans-Canada's market estimates, Western Pipe Lines had the Stone & Webster Service Corporation prepare its market study and this was presented by Mr. Ritchie and filed as Exhibit 44. A summary of the study appears as Table G-2.

Phase I

Western Pipe Lines estimates its average daily requirements (based on its sales estimate) for the first year at 140 MMCFD with peak day requirements of 180 MMCFD. Corresponding figures for the fifth year are 197 MMCFD and 240 MMCFD. Of these

requirements Northern Natural Gas Company, which serves communities in Minnesota, Iowa, South Dakota and Nebraska, is estimated to take an average of 122 MMCFD with a peak of 150 MMCFD during the first year and for the second year 150 MMCFD at 100 per cent load factor. Reference is made in Exhibit 44 to the contract between Western Pipe Lines and Northern Natural Gas Company which was filed at a previous hearing (Exhibit 104). According to Exhibit 44 the contract specifies a minimum quantity of 100 MMCFD and also provides that Northern Natural Gas Company is to have an option to buy any additional gas that Western Pipe Lines may have for export to the United States.

The contract between Western Pipe Lines and Northern Natural Gas Company is dated October 22nd, 1951. Clauses 3 and 6 of the contract might be regarded as constituting a firm agreement for the sale and purchase of 100 MMCFD of gas for a period of 20 years even though the absence of an agreement as to consideration probably makes it unenforceable by the parties themselves. Clauses 4, 5, 7, 8 and 9 of the contract dealing with surplus gas over the requirements of Saskatchewan and Manitoba contain such expressions as "Upon reasonable terms to be mutually agreed upon", "They will jointly work out mutually satisfactory terms", and "On a mutual satisfactory basis". Considering these terms in conjunction with the absence of consideration previously referred to, it would appear that the so-called agreement to purchase surplus gas is even less enforceable between the parties than the agreement with respect to the minimum quantity of 100 MMCFD. However, these clauses are at least evidence of intention to negotiate a contract now partially agreed to.

Mr. D. L. Sedgewick, Director of Markets for Northern Natural Gas Company, gave evidence related to the company's need for Canadian gas. His evidence was inconclusive. He dealt mostly with peak day requirements and line capacity, and did not offer direct confirmation of the ability and willingness of Northern Natural Gas Company to take delivery of the quantities of gas referred to in Exhibit 44.

Phase II

According to Exhibit 44 gas would be made available to the Toronto-Hamilton area in the fifth year and to the balance of the Eastern Canadian market in the sixth year following completion of Phase I.

Mention is made on page 1 of Exhibit 44 of an amendment to the contract between Northern Natural Gas Company and Western Pipe Lines whereby Western would be able in later years to reduce the sales from the then existing level to not less than 100 MMCFD in the event Western acquired additional gas for Canadian communities. Presumably, this had reference to Phase II. No copy of the amendment was filed nor was its existence confirmed by oral evidence. However, a letter from the Northern Natural Gas Company dated September 18th, 1953, was filed (Exhibit 125). This letter expressed the willingness of Northern Natural Gas Company to consider any re-negotiation of its contract with Western Pipe Lines that might be necessary to avoid any hindrance to Western's proposed revised project. This letter itself

does not constitute any waiver in whole or in part of any advantages which Northern Natural Gas Company secured under the contract (Exhibit 104) and particularly under Clauses 4, 5, 7, 8 and 9 of that contract.

Market requirements for Phases I and II are shown on Table G-2. As mentioned previously, Mr. Ritchie assumed that in the interval between the commencement of construction for Phase I and the construction of Phase II, the Toronto-Hamilton market would be built up with gas from either Union Gas Company of Canada Limited or Niagara Gas Transmission Limited but even with the additional time for market build-up his estimates are more conservative than those of Messrs. Poor and Shattuck, particularly with respect to the rate of load attachment.

Requirements for Northern Natural Gas Company for Phase II are estimated on the same basis as for the second year in Phase I; namely 150 MMCFD.

The Board is prepared to accept Western Pipe Lines' evidence with respect to sales in Canadian markets. It considers these estimates were prepared on a conservative basis. However, on the basis of the evidence, it is not convinced that Western Pipe Lines can sell the amounts of gas to Northern Natural Gas Company as presumed in Exhibit 44.

TABLE G-I

TRANS-CANADA PIPE LINES LIMITED

MARKETS FOR NATURAL GAS — ESTIMATED SALES AND REQUIREMENTS

Estimate of Sales and Requirements

H. K. Ferguson Co. Ltd. — Mr. Shattuck

Year	Firm Sales Annual MMCF	Interrupt-ible Sales Annual MMCF	Un-accounted For Gas Annual MMCF	Total Annual Require ments MMCF	Average Daily Require ments MMCF	Peak Day Require ments MMCF
First (1956)	33,027	55,544	4,429	93,000	255	181
Second (1957)	51,230	64,484	5,786	121,500	333	308
Third (1958)	62,268	66,684	6,448	135,400	371	400
Fourth (1959)	72,206	56,746	6,448	135,400	371	472
Fifth (1960)	80,820	48,132	6,448	135,400	371	534

Estimate of Sales

Ford, Bacon & Davis, Inc. — Mr. Poor

Year	Firm Annual MMCF	Interruptible Annual MMCF	Total Annual MMCF	Average Day MMCF	Peak Day MMCF
First (1957)	39,873	56,349	96,222	264	281
Second (1958)	55,577	59,264	114,841	315	357
Third (1959)	69,684	59,238	128,922	353	413
Fourth (1960)	81,357	61,620	142,977	392	512
Fifth (1961)	95,228	59,943	155,171	425	550

TABLE G-2

WESTERN PIPE LINES

MARKETS FOR NATURAL GAS — ESTIMATED SALES AND REQUIREMENTS

Stone & Webster Service Corporation — Mr. Ritchie

PHASE I

Year	Firm Sales Annual MMCF	Interrupt-ible Sales Annual MMCF	Un-accounted For Gas Annual MMCF	Total Annual Require-ments MMCF	Average Daily Require-ments MMCF	Peak Day Require-ments MMCF
First (1955)	48,913	1,623	477	51,013	140	180
Second (1956)	61,933	1,391	726	64,050	175	197
Third (1957)	64,471	1,553	972	66,996	184	214
Fourth (1958)	66,751	1,610	1,105	69,466	190	226
Fifth (1959)	68,393	1,757	1,599	71,749	197	240

PHASE I and PHASE II

First (1955)	48,913	1,623	477	51,013	140	180
Second (1956)	61,933	1,391	726	64,050	175	197
Third (1957)	64,471	1,553	972	66,996	184	214
Fourth (1958)	66,751	1,610	1,105	69,466	190	226
Fifth * (1959)	88,468	20,903	3,554	112,925	309	436
Sixth ** (1960)	97,321	26,824	4,794	128,939	353	444
Seventh (1961)	109,009	35,265	5,404	149,678	410	514
Eighth (1962)	118,470	39,024	7,250	164,744	451	582

* Fifth-year demand includes the first part of Phase II, which includes the area between Winnipeg and Brooklin, Oshawa, Toronto, Hamilton and the Stratford Lateral.

** Sixth-year demand includes the remainder of Phase II, which includes the area between Brooklin and Montreal, the Ottawa Lateral and Montreal.

TABLE G-3

COMPARISON OF MONTREAL MARKET ESTIMATES *

Year	FIRST YEAR Western Pipe Lines Stone & Webster Service Corp. Mr. Ritchie 1960	FIRST YEAR Trans-Canada Pipe Lines Ford, Bacon & Davis, Inc. Mr. Poor 1957	FIRST YEAR Trans-Canada Pipe Lines H. K. Ferguson Co. Ltd. Mr. Shattuck 1956	FIFTH YEAR Western Pipe Lines Stone & Webster Service Corp. Mr. Ritchie 1964	FIFTH YEAR Trans-Canada Pipe Lines Ford, Bacon & Davis, Inc. Mr. Poor 1961	FIFTH YEAR Trans-Canada Pipe Lines H. K. Ferguson Co. Ltd. Mr. Shattuck 1960
Annual Gas Sales:						
Residential	3,106	4,100	6,869	14,302	11,040	14,905
Commercial	1,145	5,225	1,717	3,820	9,475	3,726
Firm Industrial	1,124	10,295	4,152	5,297	13,416	9,964
Sub Total Firm Requirements	5,375	19,620	12,739	23,419	33,931	28,595
Company Use and Unaccounted For	283	981	1,415	1,230	1,696	2,072
Total Firm Requirements	5,658	20,601	14,153	24,649	35,627	30,667
Interruptible Sales	4,085	14,887	15,555	16,342	21,271	12,856
Total Requirements	9,743	35,488	29,708	40,991	56,898	43,523
Manufactured Gas	2,,882	3,564	—	2,286	3,564	—
Net Natural Gas Requirements	6,861	31,924	29,708	38,705	53,334	43,523

* All estimates in millions of cubic feet.

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